BACKGROUND READING MATERIAL FOR THE

TRAINING PROGRAMME ON

PLANNING FOR THE POWER SECTOR

conducted by

TATA ENERGY RESEARCH INSTITUTE

in collaboration with

CENTRAL ELECTRICITY AUTHORITY

and

POWER FINANCE CORPORATION

at

Hotel Oberoi Clarkes, Simla

19-24 September, 1988

teri TATA ENERGY RESEARCH INSTITUTE
7, JOR BAGH, NEW DELHI

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TIME-TABLE

Monday September 19, 1988

9 00 - 10 15	Inaugural session
10 15 - 10 45	Tea/Coffee
10 45 - 11 00	About the programme - Dr S Ramesh
11 00 - 12 10	Electric Power & Economic Development - Dr R K Pachauri
12 10 - 13 30	Long-term Forecasting for Planning - Mr M K Sambamurthy
13 30 - 14 30	Lunch
14 30 - 15 40	Short and Medium Term Forecasting - Dr Bhaskar Natarajan
15 40 - 16 00	Tea/Coffee
16 00 - 17 10	Issues in Electric Utility Planning in Developing Countries Prof M A Bernstein
17 15 onwards	Demonstration of software for short term forecasting - Dr Bhaskar Natarajan (Groups I and II)

Tuesday September 20, 1988

9 30 - 10 40	Long-term Supply Planning - I - Mr R N Srivastava & Mr M L Gupta
10 40 - 11 55	Long Term Supply Planning - II - Mr R N Srivastava & Mr M L Gupta
11 55 - 12 15	Tea/Coffee
12 15 - 13 30	Theory of Electricity Pricing - Dr S Ramesh
13 30 - 14 30	Lunch
14 30 - 15 40	Electricity Pricing in Practice - Dr S Ramesh & Dr Bhaskar Natarajan
15 40 - 16 00	Tea/Coffee
16 00 - 17 10	Time-of-day Pricing - Dr Bhaskar Natarajan
17.15 onwards	Demonstration of software for short term forecasting - Dr Bhaskar Natarajan (Groups III and IV)

Wednesday September 21, 1988

9 30 - 10 40	Investment Planning & Pricing in Germany - I - Mr D Nitz
10 45 - 11 55	Investment Planning & Planning in Germany - II - Mr D Nitz
11 55 - 12 15	Tea/Coffee
12 15 - 13 30	Transmission Planning - I - Mr J V Sastry
13.30 - 14 30	Lunch
14 30 - 15 40	Transmission Planning - II - Mr J V Sastry
15 40 - 16 00	Tea/Coffee
16 00 - 17 10	Discussion Session on Issues in Rural Electrification Discussant - Dr S Ramesh

Thursday September 22, 1988

9 00 - 10 10	Environmental Issues in Power Generation - I - Prof Ulf Hansen
10 15 - 11 30	Environmental Issues in Power Generation - II - Prof Ulf Hansen
	OUTING

Friday September 23, 1988

9 30 - 10 40	Reliability of Power Supply - I - Dr Arun Sanghvi
10 45 - 11 55	Reliability of Power Supply - II - Dr Arun Sanghvi
11 55 - 12 15	Tea/Coffee
12 15 - 13 30	Electricity Pricing in Developing Countries - Dr Bhaskar Natarajan
13 30 - 14 30	Lunch
14 30 - 15 40	Energy Conservation and Power Utilities - Mr G Sambasivan
15 40 - 16 00	Tea/Coffee
16 00 - 17 15	Discussion Session on Innovative Pricing Strategies Discussants - Dr Arun Sanghvi & Dr Bhaskar Natarajan

Saturday September 24, 1988

9 30 - 10 40	Functioning of SEBs - Mr L R Suri
10 40 - 11 55	Discussion Session on Performance of SEBs Discussant - Mr L R Suri
11 55 - 12 15	Tea/Coffee
12 15 - 13 30	Valedictory Session - Address by Mr S Rajagopal, Secretary, Department of Power
13 30 - 14 30	Lunch

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Training Programme on
PLANNING FOR THE POWER SECTOR

September 19-24, 1988

at
Hotel Oberoi Clarkes, Shimla

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Inaugural address by Shri Bahadur Chand, Chairman, CEA & Ex-Officio Secretary to the Govt. of India on the occasion of the "Training Course on Planning for Power Sector" organised by Tata Energy Research Institute on 19th September, 1988 at Shimla.

It gives me great pleasure to be in the midst of all of you who have come here all the way to attend the training course on **Planning for Power Sector** organised by TERI in collaboration with CEA and PFC. This forum will give you an exposure to the current state of art practices and techniques used in the field of planning for power generation and transmission systems. This forum will also provide you an opportunity to deliberate upon numerous problems and challenges facing the power sector today. I hope, all of you will have very meaningful and fruitful discussions amongst you and with the faculty, who have vast experience, which will benefit you in the future planning exercises for the power sector in your respective organisations.

As all of you know, the systematic planning process for power development in India started only after we attained independence in 1947. Prior to that, power sector was in a skeleton shape. The total installed capacity in such a large country like India was hardly around 1,300 MW. The power supply facilities were mainly confined to metropolitan cities and big towns only. The villages which were fortunate to have this amenity were not many. The

power supply utilities were mostly owned and controlled by various private companies.

The dawn of independence brought in the realisation for planned development of power sector for socio-economic development and upliftment of the country. Power being a basic vital key in-put for socio-economic development, due importance and priority was given to the power development programmes by the planners in successive Plan periods. Outlays of the order of about 15% to 20% were earmarked for the power sector in various Plan periods. As you all know, power sector is a highly capital intensive industry and huge investments have been made in this area since independence. The outlay which was about Rs.394 crores in the First Five-Year Plan will increase to about Rs.42,000 crores in the Seventh Plan period.

The power sector, in turn, also responded very well and has made significant and spectacular progress during the last four decades. The installed capacity today is around 55,000 MW which reflects an average annual growth rate of about 10%. This is indeed no mean achievement. But despite significant achievements made so far, the country continues to face power shortages of varying degrees in various parts of the country. This is on account of the fact that the developing countries like India often face on the one hand the dilemma of having a power

demand growth rate much higher than GDP and on the other hand the constraints of resources. The problem gets further aggravated due to the fact that the capital investment required to finance the power development programme keep on increasing considerably both on account of mounting size of the power programme and escalating capital intensity. Even with as high as about 20% of investments of the total public sector outlay earmarked for the power sector, the country is still likely to face a peaking shortage of about 20% and energy shortage of about 6% at the end of the 7th Plan period. With the tentative capacity addition programme of about 38,000 MW during the 8th Plan, the peaking and energy shortages at the end of the 8th Plan may be around 17% and 2% respectively.

The biggest challenge before all of us today is how to overcome the power shortages which have been having a crippling effect on all sectors of our economy. This problem can be overcome mainly by two ways - (a) new capacity additions and (b) optimal utilisation of our existing facilities. I would like to deal first with the new capacity addition aspect. We are fortunate in having large reserves of primary energy resources in our country in the form of coal, lignite, nuclear and hydro. These resources are very unevenly distributed and this leads to techno-economic problems in their utilisation.

A proper planned development of these various energy resources to ensure optimum development is, therefore, essential. The main issues to be dealt with pertain to regional imbalances, hydro-thermal mix and evacuation of power, etc.

The percentage of hydro share in the overall installed generating capacity in the country, which had touched about 46% at the end of Third Five-Year Plan, has been gradually declining and is likely to be only about 30% towards the end of the Seventh Plan. It may even further decline at the end of the 8th Plan. The situation in the Western and the Eastern regions would be much worse in this respect by the end of the 8th Plan with the share of hydro power being only of the order of 16% and 13% respectively. I am sure, you would agree with me that this is not at all a desirable trend viewed in the context of proper power planning. All of us associated with the power sector should feel very much concerned about this aspect and try to retrieve the situation by way of laying more emphasis on the acceleration of hydro potential development. The gestation periods for execution of hydro power projects which often extend upto 10 to 12 years or even more have have necessarily got to be reduced to improve the hydro share position. As per the present assessment, the total hydro potential is approximately 84,000 MW at 60% load factor. Out of this, hardly about 13% potential has already been

developed and about 6% is under development. It would, therefore, be seen that a large chunk of hydro potential still remains to be developed. This is a renewable source of energy and we must pay more attention to hydro development in our planning process.

The tentative coal reserves are assessed as 170.5 billion tonnes. It is anticipated that the coal production would reach 417 million tonnes by the turn of the century as against production level of about 180 million tonnes achieved in 1987-88. Lignite reserves are estimated at about 3833 million tonnes out of which about 90% are concentrated at Neyveli in Tamil Nadu. The gas reserves are estimated at about 541 billion M^3 but there are indications for finding more gas reserves as a result of intensive investigations being carried out by ONGC. The total uranium reserves are estimated at 67,000 tonnes which are equivalent to 1900 million tonnes in coal equivalent in thermal reactors and 120 billion tonnes of coal equivalent breeder reactor technology. The thorium reserves are placed at 3,63,000 tonnes in the country. Thus, there are a number of options which need to be addressed and suitable policy measures are taken for ensuring optimum utilisation of available resources of power generation in the country.

To meet the growing power demand of developing economy, we will have to make serious efforts to augment the generation capacity so as to increase

the present installed capacity by over two and a half times by the turn of the century. As per the studies carried out by the CEA, there would be need to install about 1,10,000 MW in the country during the next decade to meet a peak demand of 1,25,000 MW thereby raising the total installed capacity of 1,77,00 MW by the turn of the century. It would require an approximate outlay of about Rs.200,000 crores. However, keeping in view the resource availability, the present indications are that the new capacity addition programme during the 8th Plan period may be around 38,000 MW.

The above figures will give you a broad idea about the huge investments required for setting up new generating capacity in the country. The financial resources available in the country are short and this factor would prove to be a big constraint in achieving the objective. The other course left to us is to concentrate on optimum utilisation of existing facilities which would involve less investments and also yield quick results. The three major areas which have large potential and scope for improvement are as follows:-

(a) Optimal utilisation of existing installed capacity.

(b) Reduction in T & D Losses.

(c) Conservation of electricity.

I will now briefly touch upon these major issues.

(a) <u>Optimal utilisation of existing installed capacity.</u>

CEA has already launched a massive programme for renovation and modernisation of 34 old thermal power stations having an aggregate capacity of 13,000 MW. A loan assistance of Rs.500 crores is being provided by the Government of India to various SEBs to supplement their efforts for implementation of this programme. We must take effective steps to implement this programme with utmost earnestness and seriousness. It must be appreciated that a mere one per cent improvement in PLF on all-India basis can give an additional equivalent output of about 500 MW which would involve an investment of about Rs.700 to 800 crores or more at current level of prices. The scope for further improvement in PLF of thermal power stations in the country does exist and we must strive hard to achieve this.

CEA has also initiated action for launching a similar programme for renovation and uprating of 49 old hydro power stations with an aggregate installed capacity of about 8,400 MW. An investment of about Rs.300 crores is involved and benefits expected are of the order of additional output of about 500 MW peaking power in which we have more shortage in the country. New additional hydro capacity of this order may require an investment of Rs.750 to 1,000 crores.

(b) Reduction in T & D Losses:

As a result of thrust given by us to the rural electrification programme to increase agricultural production in the country, the distribution systems and sub-transmission systems, particularly, were expanded in a hurry to far-flung rural areas to meet the growing power demand. This consequently contributed in a major way to the increase in T & D losses which are quite high - an average all-India figure is about 21% to 22%. This is an important area which should receive our special attention. A mere one per cent reduction in T & D losses on all-India basis is equivalent to about 450-500 MW additional output. As you all know, there exists an ample scope for reduction in T & D losses in the country by taking suitable measures such as system improvements, installation of adequate reactive compensation, curbing theft of energy, etc.

(c) Conservation of Energy:

In the present context of increasing costs and endemic power shortages arising from difficulties of augmentating power supply facilities due to diverse reasons, energy conservation offers a promising solution to the problem of power shortage in our country. It is rightly said that "energy saved is energy produced". This is an area which has been neglected most in our country. About one per cent saving of electricity consumption by way of conservation measures on all-India basis tentamounts to an equivalent additional output of about 500 MW. There are many areas where

ample scope exists for effecting electricity conservation. The power sector planners must pay adequate attention to this very important and vital area.

I would now like to touch upon another important area relating to the integrated operation of our regional grid systems. I am sorry to say that our regional grid systems are not operated in the most optimal and effective manner - mostly due to lack of discipline and some time lack of mutual co-operation by the various constituents. Quite often, controversies of commercial nature or self-centred interests are allowed to ignore the overall national interests. Attempts are made to exploit the power shortage problems in the neighbouring systems and exhorbitent tariff rates are asked for and when not agreed to, generation is allowed to be backed down rather than passing it on to the neighbouring systems. I am sure, all of you would agree with me that this sort of approach defeats the very purpose and concept of formation of regional grids and ultimately a national grid. Discipline, spirit of mutual co-operation and overall national interests should be the guiding principle to ensure optimal and efficient integrated operation of our grid systems. With this approach, we can make the best use of our existing facilities and transmission systems and can come to each other's help. A number of organisations have not bothered

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to install adequate reactive compensation in their respective transmission systems. This leads to creation of low voltage problems. Particularly, in the Northern Regional Grid, this problem has assumed an alarming proportion and often generation has to be backed down in the Singrauli Complex while load shedding has to be resorted to in the capital and surrounding areas. This is indeed a sorry state of affairs. Power sector planners must take care of this important aspect to avoid such a situation.

There are numerous problem areas and important issues pertaining to the power sector which one would like to talk about in such forums. I have tried to touch upon some of them. Unfortunately, the available time does not permit me to touch many other areas. I would now like to close my address.

I am indeed very happy to inaugurate this training course on planning for power sector organised by the Tata Energy Research Institute in collaboration with CEA and PFC. I hope you will find the course and deliberations useful and beneficial.

Background Material for the Training Programme on

Planning for the Power Sector

by

Dr. R.K. Pachauri
Director
Tata Energy Research Institute
New Delhi

Comparison of Heat values of Non-commercial fuels (in calories/kg)

Fuel	Source / Agency		
	WGEP	Marathwada Survey	TERI* Experimental values
Fuelwood	4750	3800	4250
Dung	2400	2100	3890
Twigs and Other crop residues	4200	3300	3000
Rice husk			4500
Saw Dust			4200
Palm & Coconut residue			3500
Tobacco residue			4000

* As reported in 'Rural Energy Survey consumption in Godavari Delta Region', conducted by Institute of Public Enterprise, Hyderabad on behalf of Advisory Board on Energy, for the present WGEP figures have been adopted since under the category 'crop wastes' are indicated rice husks, saw dust etc.

41. The requirement of non-commercial fuels in the year 2004/05 has been estimated by the ABE on a state-wise basis using the fuel consumption patterns as obtaining in the 1978/79 Domestic Fuel Survey by the NCAER. Using the heat values of different non-commercial fuels as adopted by the WGEP and the percentage shares of different fuels obtained from the NCAER Survey, the estimated requirement of non-commercial fuels in rural and urban areas in the year 2004/05 are as follows:

Requirement of Non-commercial fuels for Rural and Urban areas in 2004/05

Item	Unit	Rural	Urban	Total
Population	Mill.	668.51	371.49	1040
Useful Energy Requirement	10^{12} Kcal	126.88	88.14	215.02
Requirement of Non-Commercial Fuels				
Fuel wood	Mill. Tonnes	187.00(136)	71.90(52.3)	258.90(188.3
Dungcake	"	132.17	18.36	150.53 ..
Crop Wastes	"	71.75(57.4)	5.25(4.2)	77.00((61.

1. Figures not within brackets assume a chulha efficiency of 8%.

2. Figures within brackets indicate the requirement of Fuelwood at 11% chulha efficiency and requirement of cropwaste at 10% efficiency: chulha efficiency for dungcake is kept unaltered at 8%. It is possible that further improvement in design, chulha efficiency may exceed these norms.

42. Material balances for the energy requirements can now be worked out for the years 1994/95, 1999/00 and 2004/05 and are set out in the following pages:

A. CONSUMPTION	Requirement (Billion Kwh)			
	1984/85*	1994/95	1999/00	2004/05
1. Industry	72.97	185.00	280.00	367.00
2. Household	15.09	46.88	82.62	145.61
3. Agriculture	21.29	35.60	40.90	45.20
4. Transport	2.88	6.47	8.28	11.67
5. Others**	11.29	27.94	42.75	59.77
6. Total Consumption Requirement	123.52	301.89	454.55	629.25
B. NON-UTILITIES				
7. Generation	11.01	25.00	30.00	35.00
8. Auxiliary Losses	1.38	2.50	3.00	3.50
9. Net Energy Available	9.63	22.50	27.00	31.50
C. UTILITIES				
10. Consumption	113.89	279.39	427.55	597.75
11. T&D Losses (%)	21.71	20	19	18
12. Energy Availability Busbar	145.49	349.24	527.84	738.96
13. Auxiliary Losses (%)	7	7	7	7
14. Generation Requirement	156.44	375.53	567.57	783.83
15. Total Generation Requirement (7+14)	167.45	400.53	597.57	818.83

* Provisional

** Others include public lighting, public water works and Sewerage, Commercial and Miscellaneous uses.

Source: CEA for 1984/85 consumption data for electricity.

Coal

Requirement of Coal (Million Tonnes)

Sector of Consumption	1984/85	1994/95	1999/00	2004/05
1. Industry	61.81	120.00	150.00	188.00
2. Household	2.15	9.00	14.00	20.00
3. Agriculture	-	-	-	-
4. Transport	9.50	8.73	7.81	6.24
5. Others	4.26	5.27	6.19	7.76
6. <u>Coal for Power Generation</u>				
Utilities	62.21 (2.15)	156.00	244.00	329.00
Non-Utilities	NA	15.00	20.00	25.00
7. Total Consumption Requirement	139.93 (2.15)	309	442	576

Figures within brackets relate to middlings

Source: For 1984/85 Consumption of Coal, Seventh Five Year Plan, Vol I, P.43, Table 3.15.

Petroleum Products

Sector of Consumption	Requirement of Petroleum Products (Million Tonnes)			
	1984/85*	1994/95	1999/00	2004/05
1. Industry	5.453	8.53	11.91	16.62
2. Household	6.684	12.59	17.27	23.70
3. Agriculture	3.84	6.50	7.74	8.00
4. Transport				
(i) HSD	8.468	16.83-21.18	22.43-28.62	31.62-40.31
(ii) MS	2.084	4.0	5.7	8.0
(iii) ATF	1.336	2.2	2.7	3.5
5. Others	0.635	0.7	0.8	1.0
6. Total Energy Use	28.50	50.72-55.70	68.55-74.74	92.44-101.13
7. Non-Energy Use	10.25	12.66-13.75	15.89-17.34	20.07-21.98
8. Total Requirement of Petroleum Products.	38.75	63.38-69.45	84.44-92.28	112.51-123.11

Refinery fuel and refinery losses are excluded which can be determined from the crude throughout in the domestic refineries and the production of refined petroleum products.

* Provisional.

Source: Indian Petroleum & Petrochemical Statistics 1984-85, Ministry of Petroleum & Natural Gas.

Non-Commercial Fuels

Fuel	Units	1984/85	2004/05
Fuelwood	Mill. tonnes	146.5	258.9(188.3)
Dungcake	" "	80.3	150.53
Crop wastes	" "	45.1	77.0(61.6)

1. Figures not within brackets assume a chulha efficiency of 8%.

2. Figures within brackets indicate the requirement of Fuelwood at 11% chulha efficiency and requirement of crop waste at 10% efficiency. Chulha efficiency for dungcake is kept unaltered at 8%. It is possible that further improvement in design, chulha efficiencies may exceed these norms.

3. Consumption of non-commercial fuels in 1984/85 is estimated on the basis of per capital consumption requirement of 0.38 tcr in rural areas and 0.40 tcr in the urban areas in the household sector. The share of commercial energy sources is substracted from the total energy consumption and the rest of the consumption is apportioned in the ratio of 65:20:15 between fuelwoods, crop waste and dungcake.

Table 4-6 Share of Total Primary Energy Requirements Supplied by Renewables in Selected Countries, 1984/85, With Projections to 2000

Country	1984/85	2000
	(percent)	
Brazil[1]	59.0	64.3
Norway	61.1	63.0
Japan	5.1	13.5
Australia	9.4	12.6
Israel	2.3	12.0
Denmark	2.0	10.0
Greece	5.9	8.9
United States	7.4	8.7
West Germany	2.5	5.5

[1]Figures for 1983 and 1993

SOURCES Ministry of Mines and Energy, "Energy Self-Sufficiency A Scenario Developed as an Extension of the Brazilian Energy Model," Government of Brazil, Brasilia, 1984, Strategies Unlimited, "International Energy and Trade Policies of California's Export Competitors," California Energy Commission Sacramento, Calif., 1987, Scott Sklar, "International Trade Policy for the Renewable Energy Industries An Assessment," *Solar Today*, March/April 1987, International Energy Agency, *Energy Policies and Programmes of IEA Countries 1986 Review* (Paris Organisation for Economic Co-operation and Development, 1987)

Table 5-2 Share of Total Energy Use Provided by Wood, Selected Countries, Early Eighties

Country	Wood Share of Total Energy Use
	(percent)
Burkina Faso	96
Kenya	71
Malawi	93
Nigeria	82
Sudan	74
Tanzania	92
China	> 25[1]
India	33
Indonesia	50
Nepal	94
Brazil	20
Costa Rica	33
Nicaragua	50
Paraquay	64

[1]Includes agricultural wastes and dung in addition to wood and charcoal

SOURCE Worldwatch Institute, based on various sources

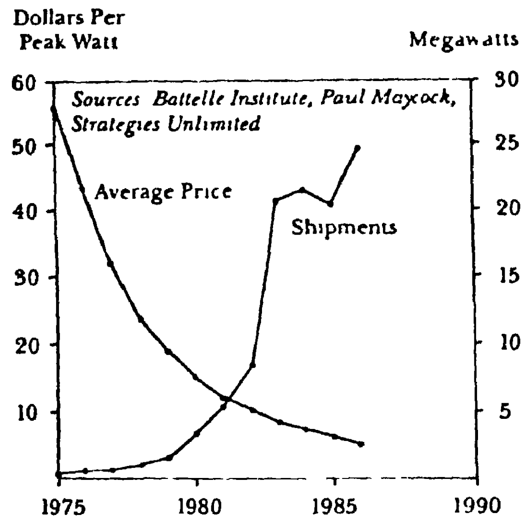


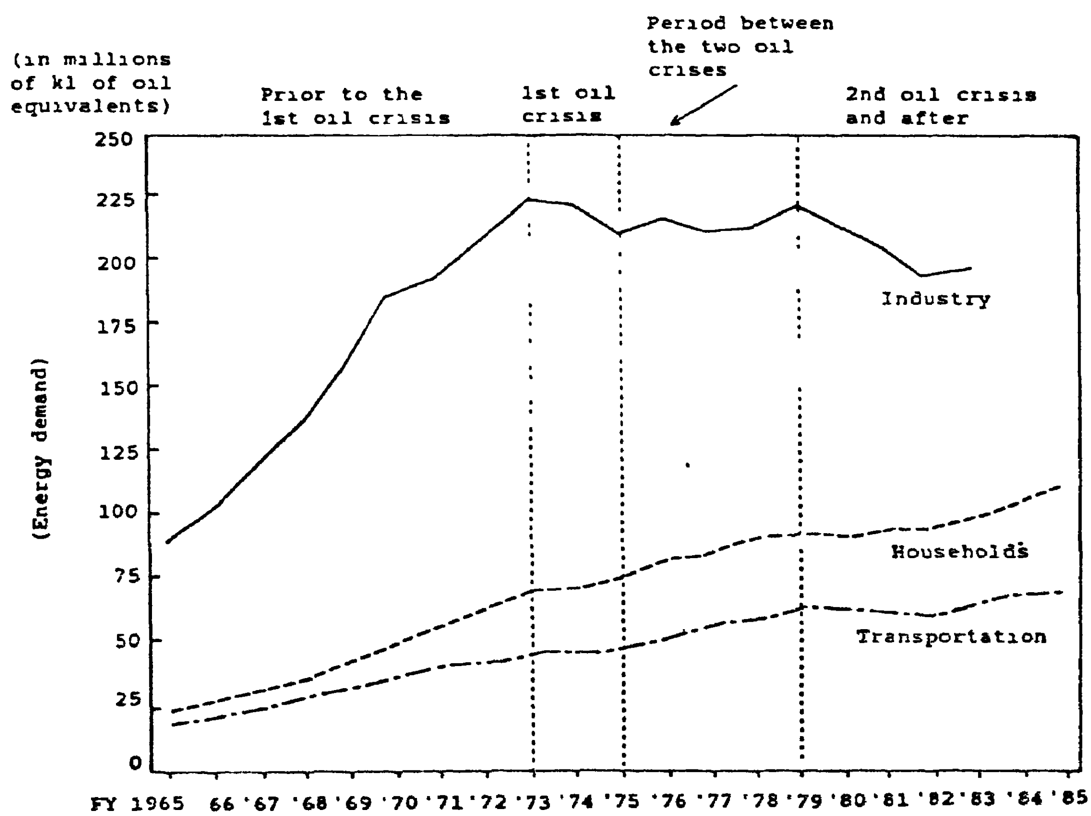
Figure 4-1. World Photovoltaic Shipments and Average Market Prices, 1975-86

Table 1-7
Changes in the Ratio of Electricity to the Total Energy Demand
(Japan)

Fiscal year	1979	1980	1981	1982	1983	1984	1985
Final domestic demand (in millions of kl of oil equivalents) (A)	417 6	410 4	394 2	375 2	395 1	406 4	412 8
Total demand for electricity (in 100 m kWh) (in millions of kl of oil equivalents) (B)	(5 291) 137 9	(5 203) 135 6	(5 227) 136 2	(5 217) 136.0	(5 531) 144 2	(5 807) 151 4	(5.993) 156 2
Ratio of electric power to the total energy demand (B/A) (%)	33 0	33 0	34 6	36 2	36 5	37 3	37 8

Source Ministry of International Trade and Industry (MITI)

Fig 1-3
Changes in Energy Demand (by sector)
(Japan)



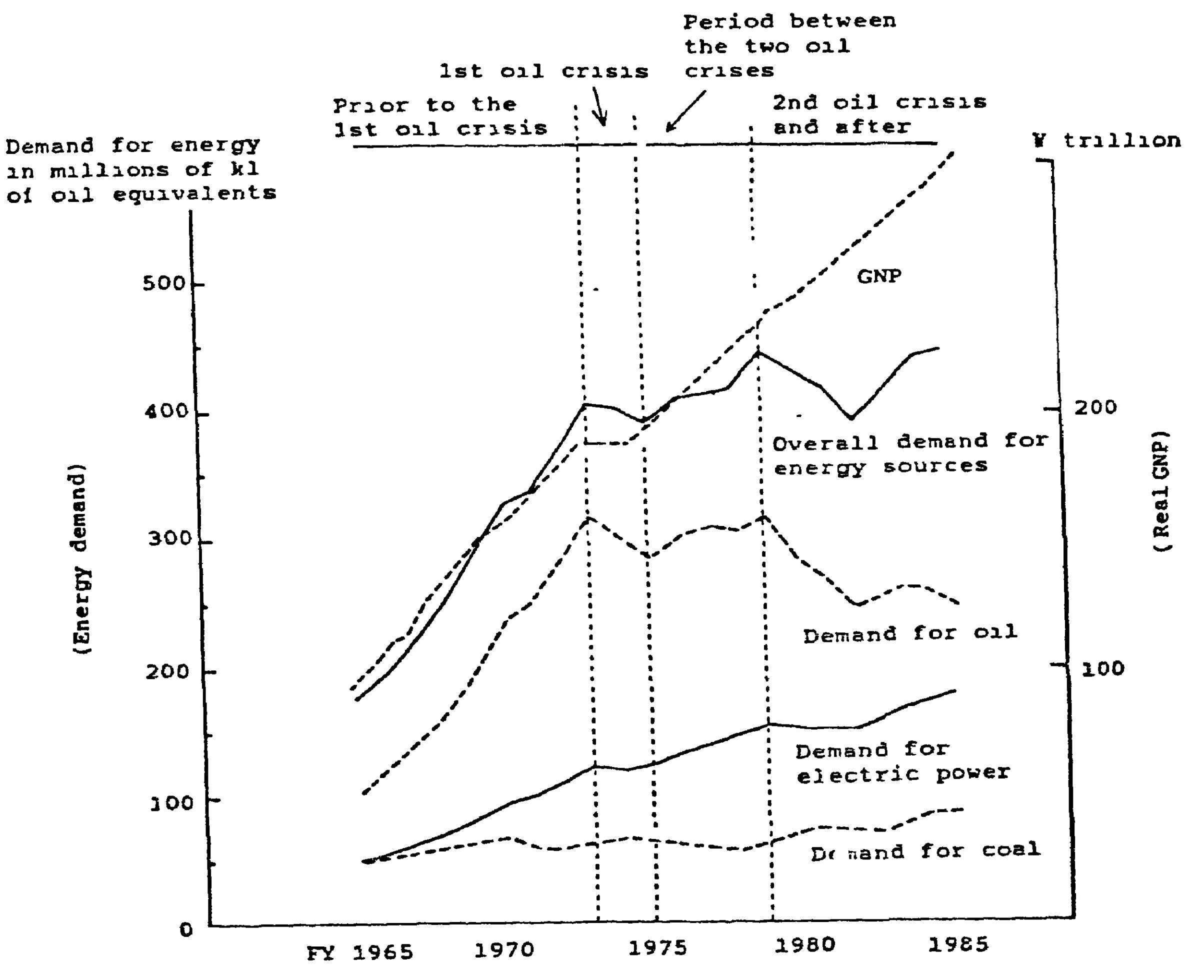
Sources Statistics on Energy Production, Supply and Demand, Survey on the Supply and Demand of Power, Handbook on the Gas Business, Statistics on Ground Transportation

Table 1-6
Changes in the Elasticity of Energy Demand to GNP
(JAPAN)

FY year	1965 - 1973	1973 - 1975	1975 - 1979	1979 - 1982	1982 - 1985
Growth rate of GNP	9 1%	1 7%	5 1%	3 5%	4 3%
Average annual growth rate of energy demand	11 1%	-2 0%	3 4%	-4 3%	4 1%
Elasticity of energy demand to GNP	1 2	-1 2	0 7	-1 2	1 0

Sources: Statistics on Energy Production, Supply and Demand, Annual Report on the Accounts of the National Economy

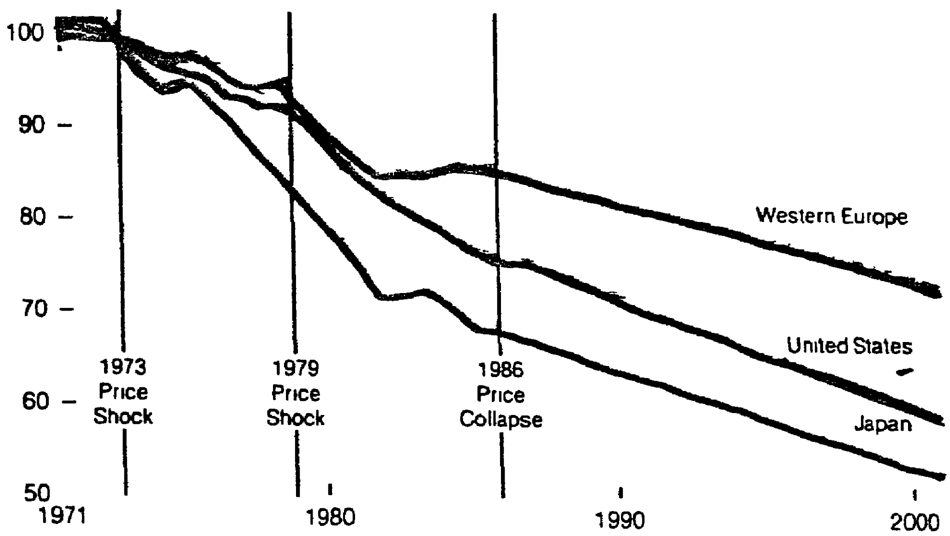
Fig 1-2
Changes in the Demand for Energy and GNP in Japan



Sources: Annual Report on the Nation's Economy; Statistics on Energy Production, Supply and Demand

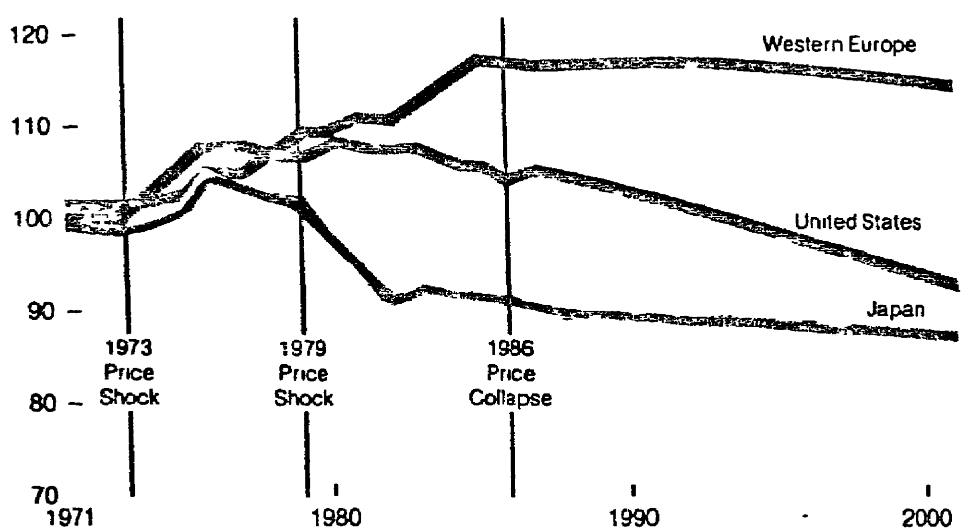
Energy Use Per Unit of GNP

1971–73 = 100



Electricity Use Per Unit of GNP

1971–73 = 100



FORECASTING

LONG TERM DEMAND FOR ELECTRIC POWER

FORECASTING:	AN OBJECTIVE PROGNOSIS INTO THIS FUTURE. A TECHNIQUE USED IN BUSINESS TO DETERMINE THE LEVELS OF ACTIVITIES IN DIFFERENT TIME HORIZONS IN THE FUTRUE FOR DECISION MAKING. THE FIRST STEP IN THE FUTRUE PROGNOSIS IS TO ESTIMATE THE DEMAND FOR THE PRODUCT OUT PUT FROM THE ENTITY.
IN THE CASE OF THE POWER SECTOR:	THE DEMAND FOR POWER ARE FORECAST BOTH IN TERMS OF ENERGY AND PEAK DEMAND. THIS IS ESSENTIAL CONSIDERING THE SPECIAL CHARACTERISTIC OF ELECTRICITY WHICH HAS TO BE GENERATED AS IT IS CONSUMED.

TIME HORIZONS OF ELECTRICITY DEMAND FORECASTS

FORECAST TIME HORIZON		PURPOSE
IMMEDIATE:	HOURLY DURING DAY-NEXT DAY; DURING WEEK- NEXT WEEK; DURING YEAR-SEASONAL VARIATIONS.	TO SCHEDULE GENRATION AND PLAN OPERATION OF POWER SYSTEMS.
SHORT TERM:	TWO TO THREE YEARS	TO PROGRESS POWER PROGRAMME MATCHING THE NEEDS-TO TAKE SHORT TERM MEASURES TO OVERCOME ANY CRISIS.
MEDIUM TERM:	FOUR TO SIX YEARS	TO TAKE INVESTMENT DECISIONS ON PROJECTS AND PLAN AND INITIATE THEIR PHASED IMPLEMENTATIO TO PREPARE FINANCING PLANS AND INVESTMENT PROFILES TO PLAN INPUTS AND SUPPLY OF EQIPMENT.
LONG TERM:	TEN TO TWENTY YEARS	TO DRAW UP PLANS FOR POWER DEVELOPMENT; DRAW UP POLICY GUIDELINES, OPTIMALITY CRITERIA AND DEVELOPMENT STRATEGIES

LONG TERM FORECAST

WHY ?

LONG TERM FORECAST IS NECESSARY :

* TO FORMULATE LONG TERM PLANS FOR POWER DEVELOPMENT.

POWER DEVELOPMENT:

* IS A LONG GESTATION ACTIVITY.
* IS HIGHLY CAPITAL INTENSIVE.
* REQUIRES CO-ORDINATION WITH OTHER ECONOMIC ACTIVITIES

LONG TERM PLANNING FOR POWER DEVELOPMENT IS NECESSARY:

* TO ENSURE THAT POWER DEVELOPMENT FOLLOWS OPTIMAL PATH.
* TO INITIATE ADVANCE ACTION FOR ESTABLISHING INFRASTRUCTURE FACILITIES.
* TO FORMULATE COMPLEMENTARY PROGRAMMES FOR PRODUCTION AND SUPPLY OF ALL INPUTS, WHICH ARE ALSO LONG GESTATION ACTIVITIES

* TO DRAW UP POLICY MEASURES, DEVELOPMENT STRATEGIES AND OPTIMISATION CRITERIA.
* TO DEVELOP ORGANISATIONAL CAPABILITIES FOR IMPLEMENTING THE POWER PROGRAMMES.

METHODOLGY FOR FORECASTING ELECTRICITY DEMANDS

DEMAND FOR ELECTRICITY IS A DERVIED ONE AND DEPENDS ON :-

* AVAILABILITY OF ADEQUATE SUPPLY OF ELECTRICITY AND
* VARIOUS SOCIO-ECONOMIC FACTORS.

THE PRICIPAL DETERMINANTS OF ELECTRICITY DEMAND ARE:

* SIZE, NATURE AND STRUCTURE OF THE ECONOMY.
* LEVEL OF ECONOMIC ACTIVITY
* LEVEL OF WELL-BEING OF THE PEOPLE AND STANDARD OF LIVING
* ENERGY RESOURCE ENDOWMENTS AND NATURE AND STRUCTURE OF ENERGY ECONOMY
* SPREAD AND INTENSITY OF ELECTRICITY USAGE.
* PRICE OF ELECTRICITY COMPARED TO PRICES OF OTHER FORMS OF ENERGY - THE ELASTICITY OF DEMAND IN RESPONSE TO CHANGES IN PRICE.
* DEMOGRAPHIC CHANGES
* STRUCTURAL CHANGES IN THE ECONOMY AND POTENTIAL FOR ECONOMIC GROWTH.
* TECHNOLOGICAL CHANGES.
* CHANGES IN CONSUMER BEHAVIOUR AND HABITS AND CONSUMER ENVIRONMENT.

IT IS NECESSARY TO ANALYSE THE PAST TRENDS IN THE GROWTHS OF ELECTRICITY CONSUMPTION AND PEAK DEMAND AND THEIR RELATIONSHIP WITH ECONOMIC AND SOCIAL ACTIVITIES AND ECONOMIC INDICATORS AND SOCIAL FACTORS.

CONSUMPTION OF COMMERCIAL ENERGY

YEAR	COAL(1) (MILLION TONNES)	ANNUAL COMPO-UNDED GROWTH RATE %	OIL(2) (MILLION TONNES)	ANNUAL COMPO-UNDED GROWTH RATE %	ELECT-RICITY(3) (TWH)	ANNUAL COMPO-UNDED GROWTH RATE %
1953-54	28.7		3.7		7.6	-
1960-61	40.4	5.0	6.7	9.1	16.7	11.9
1970-71	51.4	2.4	15.0	8.4	48.4	11.2
1980-81	70.3	3.2	22.2	4.0	89.7	6.4
1984-85	79.5	3.1	25.8	3.8	124.6	8.6
1953-54 to 1984-85	---	3.3	---	6.5	---	9.4

Note: i) Excludes coal used for power generation.

ii) Excludes oil used for non-energy purposes, for power genration and in refineries.

iii) Excludes consumption by power station auxiliaries and transmission and distribution losses.

- ELECTRICITY HAS BEEN THE MOST PREFERRED FORM OF ENERGY.

TRENDS IN ELECTRICITY CONSUMPTION

Years	Northern Region (Gwh)	Annual Compound growth rate %	Western Region (Gwh)	Annual compound growth rate %	Southern Region (Gwh)	Annual Compound growth rate %	Eastern Region (Gwh)	Annual Compound growth rate %	North Eastern Region (Gwh)	Annual Compound growth rate %	All-India (Gwh)	Annual Compound growth rate %
1950	648	-	1477	-	998	-	1018	-	5	-	5551	
1955	978	8.58	2507	11.16	1785	12.33	1811	12.21	8	9.86	9158	10.53
1960-61	2537	21	4582	12.82	3812	16.99	5602	25.34	42.3	38.52	16711	12.78
1965-66	6006	18.8	8092	12.05	6747	11.52	8823	9.51	108.2	20.66	29880	12.32
1970-71	11116.4	13.1	13760.8	11.2	12339.6	12.83	10880.9	4.28	335.0	25.36	48436	10.14
1975-76	16329.2	7.99	19199.5	6.89	16296.2	5.72	13620.6	4.59	566.3	11.07	66024	6.39
1980-81	23485	7.54	28290	8.06	22691	6.84	14419	1.15	776	6.50	89661	6.31
1984-85	32368	8.35	39654	8.81	32327	9.25	19000	7.14	1247	12.59	124597	8.57
1950 to 1960-61	-	14.60	-	11.98	-	14.60	-	18.59	-	23.80	-	11.65
1960-61to 1970-71	-	15.92	-	11.62	-	12.17	-	6.86	-	22.99	-	11.23
1970-71to 1980-81	-	7.77	-	7.47	-	6.28	-	2.86	-	8.76	-	6.35
1950 to 1984-85	-	12.1	-	10.08	-	10.69	-	8.92	-	17.48	-	9.51

Notes : 1. The electricity consumed by the industries and the Railways from their captive installations is included except in the case of Region-Wise break-down for 1950 and 1955.

2. The consumption of some of the Union Territories is included in all-India total only.

* GROWTH OF ELECTRICITY CONSUMPTION ACHIEVED AVERAGE ANNUAL RATES HIGHER THAN 12% P.A. DURING THE SECOND AND THIRD PLANS, AND AVERAGES PRESENTLY ABOUT 9-10% P.A.

* GROWTH IN THE NORTHERN REGION HAS BEEN THE FASTEST AVERAGING 12% P.A.

* GROWTH HAS BEEN GOVERNED TO A LARGE EXTENT BY AVAILABILITY OF ELECTRICITY.

TREND IN ELECTRICITY CONSUMPTION IN DIFFERENT ECONOMIC SECTORS

Year	Agriculture		Industries		Residential& Commercial		Others		Total
	MKwh	%share	MKwh	%share	MKwh	%share	MKwh	%share	MKwh
1950	162	2.92	3998	72.02	833	15.00	558	10.05	5551
1955	255	3.78	6745	73.65	1365	14.90	793	8.66	9158
1960-61	833	4.98	12455	74.53	2340	14.00	1083	6.48	16711
1965-66	1892	6.33	22020	73.69	4005	13.40	1962	6.56	29880
1970-71	4470	9.23	34291	70.80	6412	13.24	3262	6.73	48436
1975-76	8721	13.21	43346	65.65	9328	14.12	4629	7.01	66024
1980-81	14489	16.16	55363	61.75	13928	15.53	5881	6.56	89661
1984-85	21194	17.01	73455	58.95	22001	17.66	7947	6.38	124597

Note : The consumption in the industrial sector includes supplies from captive power plants (i.e. non-utilities) also.

* ELECTRICITY IS USED PIMARILY IN THE PRODUCTIVE
* SECTORS OF ECONOMY.
* INDUSTRIAL SECTOR HAS BEEN THE MAJOR CONSUMER.
* USE OF ELECTRICITY IN AGRICULTURE HAS STEADILY INCREASED AND ITS SHARE IN ELECTRICITY CONSUMPTION IS NOW ABOUT 20%

TRENDS IN ELECTRICITY CONSUMPTION IN INDUSTRIAL SECTOR AND PERCENTAGE OF THE OVERALL ELECTRICITY CONSUMPTION

(MKWH)

Region	1950	1955	1960-61	1965-66	1970-71	1975-76	1980-81	1984-85
Northern	302 (46.6)	458 (46.8)	1518 (59.8)	4373.1 (71.6)	7229.8 (65.0)	8931.0 (54.7)	11614 (49.2)	14314 (44.2)
Western	927 (62.8)	1720 (68.6)	3432.8 (74.9)	6132.3 (75.8)	10071.6 (73.2)	13199.5 (68.7)	18154 (64.9)	24671 (62.2)
Southern	663 (66.4)	1185 (66.4)	2686 (68.7)	4322.4 (64.1)	8201.4 (66.5)	10535.7 (61.6)	14037 (61.9)	19273 (59.6)
Eastern	712 (69.9)	1328 (73.3)	4773.7 (85.2)	7137.8 (80.9)	8595.4 (79.0)	10383.4 (76.2)	10874 (75.4)	14488 (76.2)
North-Eastern	1 (20.0)	2 (25.0)	25 (59.1)	53.3 (49.3)	192.1 (57.3)	289.2 (51.1)	484 (62.4)	709 (56.9)
All - India	3998 (72.0)	6745 (73.6)	12455 (74.5)	22020 (73.7)	34291 (70.8)	43346 (65.6)	55363 (61.7)	73455 (59.9)

Note: i) The figures in bracket () show percentage share in the overall electricity consumption.

ii) The consumption includes supply from captive power plants i.e. non-utilities. However, for the years 1950, 1955 the supply from captive power plants is included only in all-India totals due to non- availability of breakdown by regions.

* INDUSTRIAL SECTOR IS MAJOR USER OF ELECTRICITY THOUGH ITS SHARE HAS DECLINED FROM 72% IN 1950 TO ABOUT 60% AT PRESENT.
* THE DECLINE FROM MID-SIXTIES IS MAINLY DUE TO INCRESING USE OF ELECTRICITY IN AGRICULTURE.

TRENDS IN ELECTRICITY CONSUMPTION IN AGRICULTURAL SECTOR AND ITS SHARE IN THE OVERALL ELECTRICITY CONSUMPTION

Region	1950	1955	1960-61	1965-66	1970-71	1975-76	1980-81	1984-85	1985-86
Northern	85	102	284.2	553.4	1613.6	3579.8	6651	8894	9320
	(13.0)	(10.4)	(11.2)	(9.1)	(14.5)	(21.9)	(28.4)	(27.5)	(28.3)
Western	3	8	38.3	201.9	826.7	1843.3	3406	5709	6176
	(0.2)	(0.2)	(0.3)	(2.5)	(6.6)	(9.6)	(12.1)	(14.4)	(15.2)
Southern	70	137	484.2	101.1	1928.6	2777.6	3859	5787	6977
	(7.0)	(7.7)	(12.4)	(16.3)	(15.6)	(17.0)	(16.8)	(17.9)	(21.8)
Eastern	4	8	19.7	35.3	98	514.8	566	774	1037
	(0.4)	(0.4)	(0.4)	(0.4)	(0.9)	(3.8)	(3.7)	(4.1)	(6.3)
North-	-	-	-	0.1	0.3	5.5	7	30	21
Eastern	(-)	(-)	(-)	(0.1)	(0.1)	(1.0)	(0.7)	(2.4)	(1.6)
All-	162	255	833	1892	4470	8721	14489	21194	23522
India	(2.9)	(3.8)	(5.0)	(6.3)	(9.2)	(13.2)	(16.1)	(17.0)	(19.1)

The figures in bracket () show percentage share of the overall electricity comsumption.

* CONSUMPTION IN THE AGRICULTURE SECTOR HAS REGISTRED RAPID GROWTH SINCE MID-SIXTIES.

* GROWTH IN THE NORTHEN REGION HAS BEEN PHENOMENAL.

GROWTH IN PEAK LOAD

(MW)

Region	1960-61	1965-66	1970-71	1975-76	1980-81	1985-86
Northern	720	1294	2647	3771	5883	8080
Western	1013	1468	2565	3576	5383	7805
Southern	775	1446	2663	3713	4909	7073
Eastern	1029	1363	1788	2235	2706	3480
North-Eastern	14	34	80	157	208	374
All India Total	3551	5605	9743	13452	19089	26762

REGIONAL POWER SYSTEM LOAD FACTORS

(Per cent)

Years	Northern Region	Western Region	Southern Region	Eastern Region	North-Eastern Region	All India
1970-71	57.0	67.0	63.0	63.0	50.0	62.0
1975-76	57.7	70.2	59.9	69.4	47.2	63.5
1979-80	56.4	71.0	66.7	63.5	57.3	64.1
1980-81	53.3	69.7	65.2	60.8	52.0	62.0
1984-85	63.7	74.6	66.3	65.3	51.0	67.7
1985-86	61.1	74.5	66.3	66.3	51.3	66.9

SEASONAL VARIATION IN PEAK LOADS

(Per cent)

Region	Ist Quarter April-June	II Quarter July-Sept.	III Quarter Oct.-Dec.	IV Quarter Jan.-March
Northern	90	95	95	100
Western	90	90	98	100
Southern	84	92	95	100
Eastern	90	95	100	98
North-Eastern	87	95	100	95

RATES OF GROWTH OF ELECTRICITY CONSUMPTION & NSDP

(per cent per annum compound)

Rates of Growth		Northern Region	Western Region	Southern Region	Eastern Region	North-Eastern Region	All-India
1960-61 to 1965-66	E.C.	18.80	12.05	11.52	9.51	20.66	12.32
	NSDP	2.03	1.17	1.70	2.94	4.15	2.00
1965-66 to 1970-71	E.C.	13.1	11.20	12.83	4.28	25.36	10.14
	NSDP	5.79	5.36	5.08	2.15	3.22	4.66
1970-71 to 1975-76	E.C.	7.99	6.89	5.72	4.59	11.07	6.39
	NSDP	2.48	3.65	2.94	2.50	3.81	2.93
1975-76 to 1980-81	E.C.	7.54	8.06	6.84	1.15	6.50	6.31
	NSDP	4.03	4.03	2.29	2.91	3.77	3.39
1980-81 to 1983-84	E.C.	9.90	7.7	5.4	6.80	14.1	7.6
	NSDP	5.50	5.21	4.85	4.71	5.22	5.12
1960-61 to 1983-84	E.C.	11.52	9.29	8.69	5.09	15.46	8.61
	NSDP	3.82	3.76	3.24	2.89	3.93	3.48

E.C. = Electricity Consumption
NSDP = Net State Domestic Product

ELECTRICITY CONSUMPTION HAS GROWN FASTER THAN THE ECONOMIC GROWTH INDICATING THAT THE ECONOMY IS BECOMING GRADUALLY MORE ELECTRICITY INTENSIVE DUE TO :

- SPREAD AND POPULARISATION OF ELECTRICITY USE.
- ESTABLISHMENT OF ENERGY INTENSIVE INDUSTRIES.

ELECTRICAL ENERGY - **N.S.D.P. ELASTICITY COEFFICIENT**

Period	Northern Region	Western Region	Southern Region	Eastern Region	North Eastern Region	All India
1960-61 to 1965-66	9.26	10.30	6.78	3.23	4.98	6.16
1965-66 to 1970-71	2.26	2.09	2.53	1.99	7.88	2.18
1970-71 to 1975-76	3.22	1.89	1.95	1.84	2.91	2.18
1975-76 to 1980-81	1.87	2.00	2.99	0.39	1.72	1.86
1980-81 to 1983-84	1.80	1.48	1.11	1.44	1.82	1.48
1960-61 to 1983-84	3.02	2.47	2.68	1.76	3.93	2.47
1970-71 to 1983-84	2.19	1.81	1.95	1.19	2.42	1.84

DEMAND FORECASTING TECHINIQUES IN EARLY STAGES OF POWER DEVELOPMENT.

* POWER SYSTEMS WERE MOSTLY ISOLATED SERVING SMALL AREAS - MOSTLY RADIAL SYSTEMS.
* IT WAS CUSTOMARY TO MAKE A DETAILED LOAD SURVEY OF INDIVIDUAL SERVICE AREAS BASED ON A DEMAND ASSESSMENT OF INDIVIDUAL MAJOR CONSUMER AND GROUPS OF SMALL CONSUMER - THE TECHINIQUE WAS TO ESTIMATE CONSUMER-WISE CONNECTED LOAD, APPLY A DEMAND FACTOR TO ARRIVE AT CONSUMER-WISE MAXIMUM DEMANDS AND APPLY A DIVERSITY FACTOR TO ASSESS THE SYSTEM PEAK DEMAND.
* ASSESSMENT OF ENERGY REQUIREMENT WAS IGNORED. POWER STATIONS WERE DESIGNED INDIVIDUALLY OR COLLCTIVELY TO MEET THE SYSTEM DEMANDS FOR WHICH THE LOAD FACTORS WERE ASSESSED.

SOPHISTICATED METHODOLOGIES FOR ELECTRICITY FORECASTING.

* WITH POWER SYSTEMS EXPANDING TO COVER LARGER AREAS AND TO CATER TO A LARGE AND DIVERSIFIED VARIETY OF CONSUMERS, THE MICRO - CONSUMER-WISE APPROACH BECAME CUMBERSOME AND UNMANAGEBLE.

* DEVELOPMENT OF ECONOMETRIC AND INPUT-OUTPUT MODELLING TECHNIQUES LED TO DEVELOPMENT OF ENERGY MODELS FOR FORECASTING.

* SIMULTANEOUSLY CONCEPTS OF INTEGRATED ENERGY DEVELOMENT AND REGIONAL APPROACH TO COORDINATE AND OPTIMISE ENERGY SUPPLIES HAS EMERGED. THIS LED TO CONSIDERATION OF ELECTRICITY FORECASTS AS AN INTEGRAL PART OF OVERALL ENERGY FORECASTS.

* INITIALLY BECAUSE OF LIMITATIONS OF COMPUTING TECHQUES, MODELS WERE SIMPLE RELATING ENERGY CONSUMPTION WITH ECONOMIC INDICATORS SUCH AS TIME, NATIONAL INCOME AND INDUSTRIAL OUTPUT. LATER MORE COMPLEX MODELS BASED ON INDIVIDUAL AND GROUPS OF END-USERS WERE DEVELOPED.

* ADVANCES IN COMPUTER BASED TECHNIQUES HAVE LED TO HIGHLY COMPLEX MODELS FOR DEMAND FORECASTING. THESE HAVE IMPROVED THE QUALITY OF FORECASTS AND MADE THEM MORE SCIENTIFIC.

* INSPITE OF THE VASTLY IMPROVED TECHNIQUES, FORECASTING FUTURE DEMANDS FOR ELECTRICITY INVOLVES CONSIDERABLE RISK IN VIEW OF UNCERTAINTIES ASSOCIATED WITH:-
  i) FUTURE ECONOMIC DEVELOPMENT AND ITS STRUCTURE.
  ii) ENERGY PRICES AND FUTURE OF ENERGY-ECONOMY AT THE NATIONAL AND INTERNATIONAL LEVEL AND
  iii) CONSUMER ASPIRATIONS, RESPONSES AND BEHAVIOUR.

* IN VIEW OF UNCERTAINTIES, AN APPROACH OF PREPARING FORECASTS CORRESPONDING TO DIFFERENT ECONOMIC SCENARIOS IS FOLLOWED. SUCH TECHNIQUES GIVE THE UPPER AND LOWER BOUNDS WITHIN WHICH FORECASTS WILL LIE.

* CHOICE OF FORECASTING TECHNIQUE WOULD ULTIMATELY DEPEND ON THE AVAILABILITY OF DATA AND THE MOTIVATION FOR DEVELOPING REALISTIC FORECASTS OF FUTURE DEMANDS

INDIAN EXPERIENCE IN ELECTRICITY DEMAND FORECASITNG.

HISTORICAL

PRE-PLANNING ERA: ELECTRIC POWER UTILITIES WERE SMALL AND NUMEROUS. FORECASTING TECHNIQUES ADOPTED BY THEM WERE BASED ON DETAILED MICRO-CONSUMER BASED APPROACH FOR EACH SERVICE AREA.

MID-FIFTIES: CENTRAL WATER AND POWER COMMISSION (POWER WING) INITIATES A SYSTEM OF DETAILED POWER SURVEYS IN ALL STATES/ADMINISTRATIVE UNITS TO FACILITATE POWER PLANING.

1962 A SYSTEM OF ANNUAL POWER SURVEYS INTRODUCED. THIS SURVEY IS FOR FORECASTING DEMAND OF EACH INDIVIDUAL STATE/SYSTEM AND AGGREGATE THEM TO ARRIVE AT REGIONAL/NATIONAL LEVEL FORECASTS. THE COMMITTEE HAD NATIONWISE PRATICIPATION INCLUDING REPRESENTATIVES FROM GOVT DEPTS, PLANNING COMMISSION, STATE ELECTRICITY BOARDS AND GOVT. AND ACADEMIC INSTITUTIONS. THIS SYSTEM OF SURVEY IS CONTINUING AND 13TH POWER SURVEY WAS COMPLETED RECENTLY. METHODOLOGY FOR FORECASTING HAS BEEN IMPROVED BASED ON DATA AVAILABILITY. THIS IS THE ONLY FORECAST AVAILABLE AT THE DISAGGREGATED STATE/SYSTEM LEVEL.

1965 - ENERGY SURVEY OF INDIA STUDIES.

SECOND/THIRD PLAN	- PLANNING COMMISSIION DEVELOPS INPUT-OUTPUT AND MATERIAL BALANCE TECHNIQUES FOR PERSPECTIVE PLANNING. FORECASTING OF ENERGY DEMAND IS CARRIED OUT AS PART OF PERSPECTIVE PLANNING EXERCISE FOR DEVELOPMENT PERSPECTIVE INCORPORATED IN EACH PLAN
1974	- FUEL POLICY COMMITTEE PROJECTIONS.
1979	- WORKING GROUP ON ENERGY POLICY PROJECTIONS
1979-80	- ENERGY MODELLING STUDIES IN PLANNING COMMISSION BY CONSULTANT - DR. J. PARIKH.
1981-82	CEA UNDERTAKES A COMPREHENSIVE DETAILED POWER SURVEY IN CONNECTION WITH FORMULATION OF LONG TERM PLAN.
1985	- ADVISORY BOARD ON ENERGY STUDIES "TOWARDS A PERSPECTIVE ON ENERGY DEMAND AND SUPPLY IN INDIA IN 2004/05."
1986	- PLANNING COMMISSION SETS UP ENERGY DEMAND SCREENING GROUP. IT PROJECTS DEMANDS FOR ELECTRICITY BASED ON SECTORAL APPROACH.

CEA's LONG-TERM PLAN- 1983.

TIME- HORIZON: 1994-95

SPATIAL UNIT: ALL-INDIA - REGIONS.

METHODOLOGY: SECTORAL PROJECTIONS:

i) INDUSTRIAL SECTOR - ECONOMETRIC MODEL BASED ON INDUSTRIAL VALUE ADDED AND TIME AS VARIABLE ($E = a + bv + ct$)

ii) AGRICULTURAL SECTOR : NO OF PUMPSETS AND SPECIFIC ELECTRICITY CONSUMPTION.

iii) DOMESTIC & OTHERS TREND METHOD

13TH POWER SURVEY

TIME HORIZON: 2004-05.

SPATIAL UNIT: STATES/UTS/SYSTEMS

METHODOLOGY: (1) UPTO 1990-91 - DETAILED PROJECTIONS BASED ON PARTIAL END-USE METHOD.

END-USE METHOD FOR PROJECTING DEMANDS OF

- INDUSTRIAL & NON-INDUSTRIAL LOADS WITH A DEMAND OF IMW AND ABOVE

- ARGICULTURAL PUMP-SETS
- RAILWAY TRACTION

TREND METHOD HAS BEEN USED FOR PROJECTING DEMAND OF:

- DOMESTIC HOUSE HOLDS
- COMMERCIAL ESTABLISHMENTS
- PUBLIC LIGHTING.
- PUBLIC WATER-WORKS.

(ii) 1991-92 TO 1994-95 : EXTRAPOLATING CATEGORY-WISE CONSUMPTION ASSUMING SAME GROWTH RATES AS ARRIVED AT FOR PERIOD UPTO 1990-91.

(iii) 1995-96 TO 2004-05 : EXTRAPOLATING OVER-ALL REQUIREMENT OF ELECTRICITY IN STATE/UT.

METHODOLOGY FOR SHORT-TERM LOAD FORECASTING
A CASE STUDY OF DELHI

Bhaskar Natarajan and Gopika Bhagat

Abstract

This paper presents a method for short term forecasting of electricity demand for Delhi. The method is based on the ARIMA model and can be applied by other utilities. The model is based on historical data and shows smaller forecast errors than other models currently used in India.

Introduction

Utilities in developed countries (e.g. France, U.S.A., U.K., Korea) have developed sophisticated models for predicting demand for electricity in the short-term. This enables the utilities to plan their generation accordingly and to introduce merit-order generation to some extent. If the need arises, the utilities can inform the neighbouring systems of their need to import power. In India, utilities still adopt the thumb rule method for estimating hourly loads. In terms of exchanging power from other utilities, there is little discipline - one of the major reasons being the absence of a forecasting methodology for hourly demand in their systems.

Very short-term load forecasting could mean predictions of the load for the next hour to the next couple of

days. These forecasts would be very useful especially for utilities in India, which operate under severe shortage conditions. The forecasts could also be used to inform consumers who are likely to be affected by load shedding which is often resorted to by utilities in order to stabilize the system. In this paper, we present a methodology to forecast hourly loads for one or two days in the future. Such short-term forecasting is important for utilities for planning operations.

The 'autoregressive integrated moving average model' (ARIMA) uses past data of a variable to predict future values of the same variable. The model is defined as ARIMA (p,d,q) for Y(t) as:

$$Y(t) = A + \{b_1 . Y_{t-1} + \ldots . b_p . y_{t-p}\} +$$
$$\{e_t - c_1 e_{t-1} - \ldots . c_q . e_{t-q}\}$$

where p is the degree of the AR process;

d is the degree of differenciation; and

q is the degree of the MA process.

Other work done in this area includes an On-Line electric load forecasting model' by June Ho Park (1), 'On-line load forecasting for energy control centre application' by G.D. Irisarri, S.E. Widergien and P.D.Yehsakul (2), and 'Short term load prediction for economic dispatch of generation' by D.W. Ross et. al (3). These models however use exponential smoothing,

Fourier analysis and a combination of different models for forecasting.

June Ho Park (1) divided the load into two components, normal and residual load for predicting one hour's load in the future. The model uses load data for 4 days in the week viz. Tuesday, Wednesday, Thursday and Friday. The normal load denotes load which would take place under normal conditions and is obtained by the exponential smoothing method. The residual load is the remaining load which has an average of zero but a high variance.

The total load is

$$P_r(i,j) = P_N(i,j) + P_R(i,j)$$

$$i: 1,2....365 \text{ days}, \quad j: 1,.....24 \text{ hours}$$

where

$P_r(i,j)$: actual load at j hour of i day

$P_N(i,j)$: normal load at j hour of i day

$P_R(i,j)$: residual load at j hour of i day

The normal load is given by applying exponential smoothing to the equation above to get

$$P_N(i+1,j) = (1 - \alpha)\, P_N(i,j) + P_r(i,j)$$

where, α is the smoothing factor.

The residual load $P_R(i,j)$ is indicated by $Z_1, Z_2 .....Z_t$ where, Z_t is the residual load at time t. The ARIMA model is expressed as

$$Z_t = \phi_1 Z_{t-1} + \phi_2 Z_{t-2} \ldots \phi_p Z_{t-p} + a_t +$$

$$\theta_1 a_{t-1} + \theta_2 a_{t-2} \ldots . \theta_q a_{t-2}$$

where,

a_t : white house

ϕ : quotient of Z_t time series

θ : quotient of a_t time series

Hence, the equation for forecasting load one hour ahead can be expressed as

$$\hat{P}_r(t + 1/t) = \hat{P}_N(t+1/t-23) \quad \hat{Z}(t+1/t)$$

where,

$\hat{P}_r(t+1/t)$: Total load forecasting value of t + 1 at t hour;

$\hat{P}_N(t+1/t-23)$: Normal load forecasting value of t + 1 at t-23;

$\hat{Z}(t+1/t)$: Residual load forecasting value of t+1 hour at t hour.

W.R. Cristiaanse (4) developed a model of hourly loads for one week, without seperating the weekends. A fourier series was used and the model was of the form

$$K(t) = C + \sum_{i=1}^{m} (a_i \operatorname{Sin} W_i t + b_i \operatorname{Cos} W_i t)$$

Where C is the constant and the fourier series has "m" frequencies. The autocorrelation functions and power spectra were used to determine the harmonics required for an adequate description of the waveforms. The model forecasts loads for 1 hour to 1 week with the standard

error for lead times of 1 to 24 hours ranging from 2 to 4%.

Development of the model

The hourly load was defined as having the following components:

$$LOAD(i) = N(i) + C(i) + T(i) + S(i) + E(i)$$

where LOAD(i) is the hourly load at hour i; and N(i), C(i), T(i), S(i) and E(i) are the base, cyclical, trend, seasonal and random error components at hour i, respectively.

Data on hourly loads for a period of one year were collected from DESU (Delhi Electric Supply Undertaking). Since load patterns for weekends, holidays and special days are distinctly different from the pattern for weekdays, all data pertaining to holidays (weekends and special days) were eliminated for the analysis. A plot of one year's hourly load data indicated a cyclical (seasonal) element and a trend component indicating an increase in the consumption base during the year. One month's data is characterised by daily cycles but the lack of a time trend (see Fig.1). Hence, data on hourly loads for one month were used to develop the model.

Based on data for one month, it can be assumed that the hourly load data has no seasonal or trend component.

be estimated by selecting suitable ARIMA parameters. The data was smoothened using the moving average method. An autoregressive process was fitted to the smoothened data to arrive at the coefficients estimating the weight of the past periods on current hourly loads.

Estimates for the model were carried out using hourly load data of the DESU system for the month of January 1986 (Fig.1). The autocorrelations (plotted in Figure 2) exhibits a distinct pattern indicating the decreasing correlation of Y_t with Y_{t-1}, Y_{t-2} etc. The dual peak occuring during the day is clearly seen. A plot of hourly load data and 12 period moving averages is given in Fig.3 and a plot of their autocorrelations in Fig.4. The effect of smoothening on the autocorelation is quite obvious. Using the model, estimates of hourly loads were made and deviations from observed loads were worked out (see Fig.5 and 6). It can be seen that 80 per cent of the values estimated have an error less than 10 per cent. The equation (to fit the data) obtained by using this model, had a goodness of fit (R^2) of 0.995.

Conclusions

The ARIMA model, applied to DESU, has been found to give predicted values within a 10 per cent range. Some additional work needs to be done to optimise the time period to be used in order to minimize the forecast errors.

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4. W.R.Christiannse, "Short-term load forecasting using general exponential smoothing", IEEE Trans., Vol. PAS-90, No.2, Mar./Apr. 1971, pp.900-910.
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Figure 1

Hourly load-data for one week

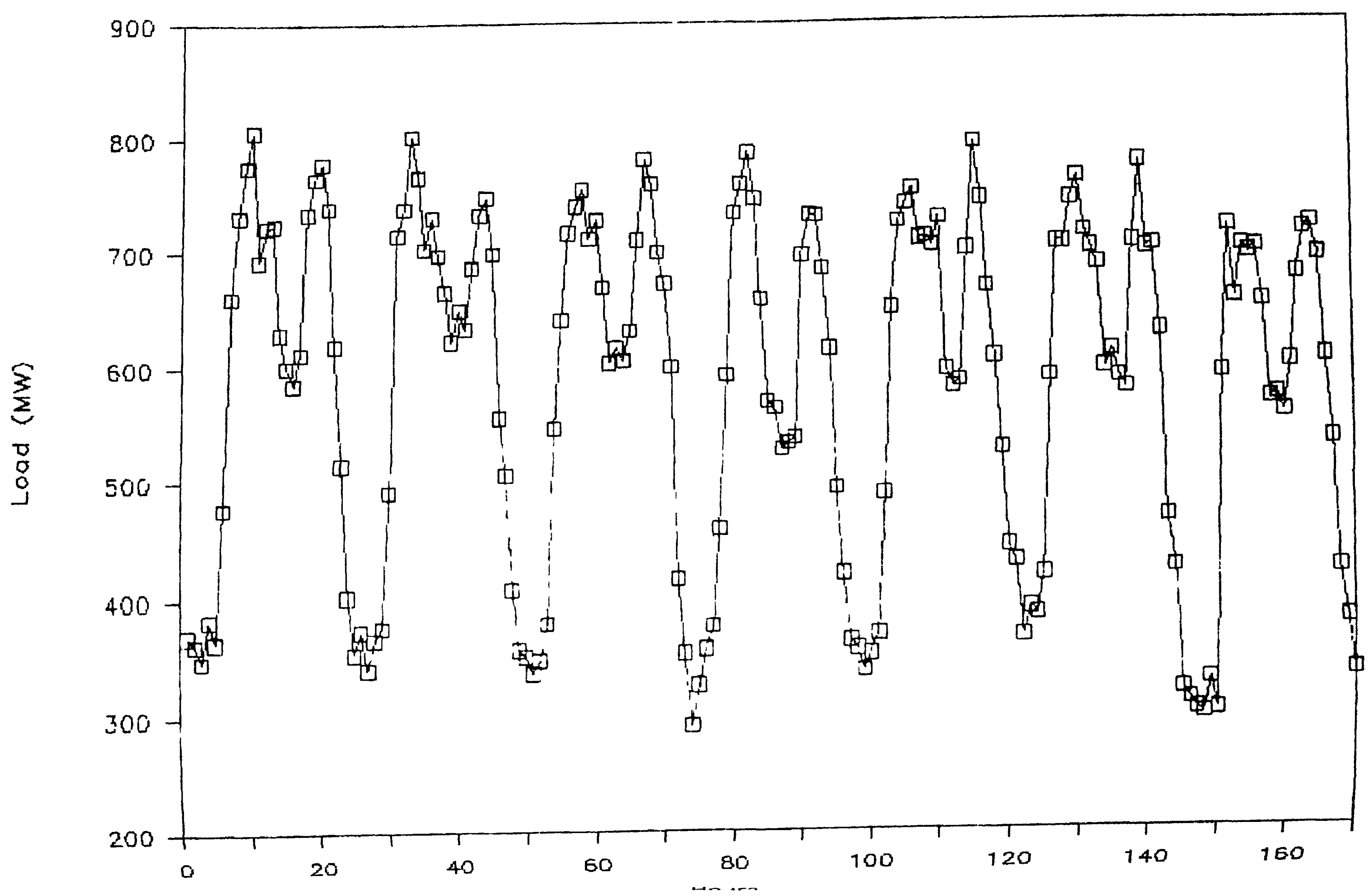
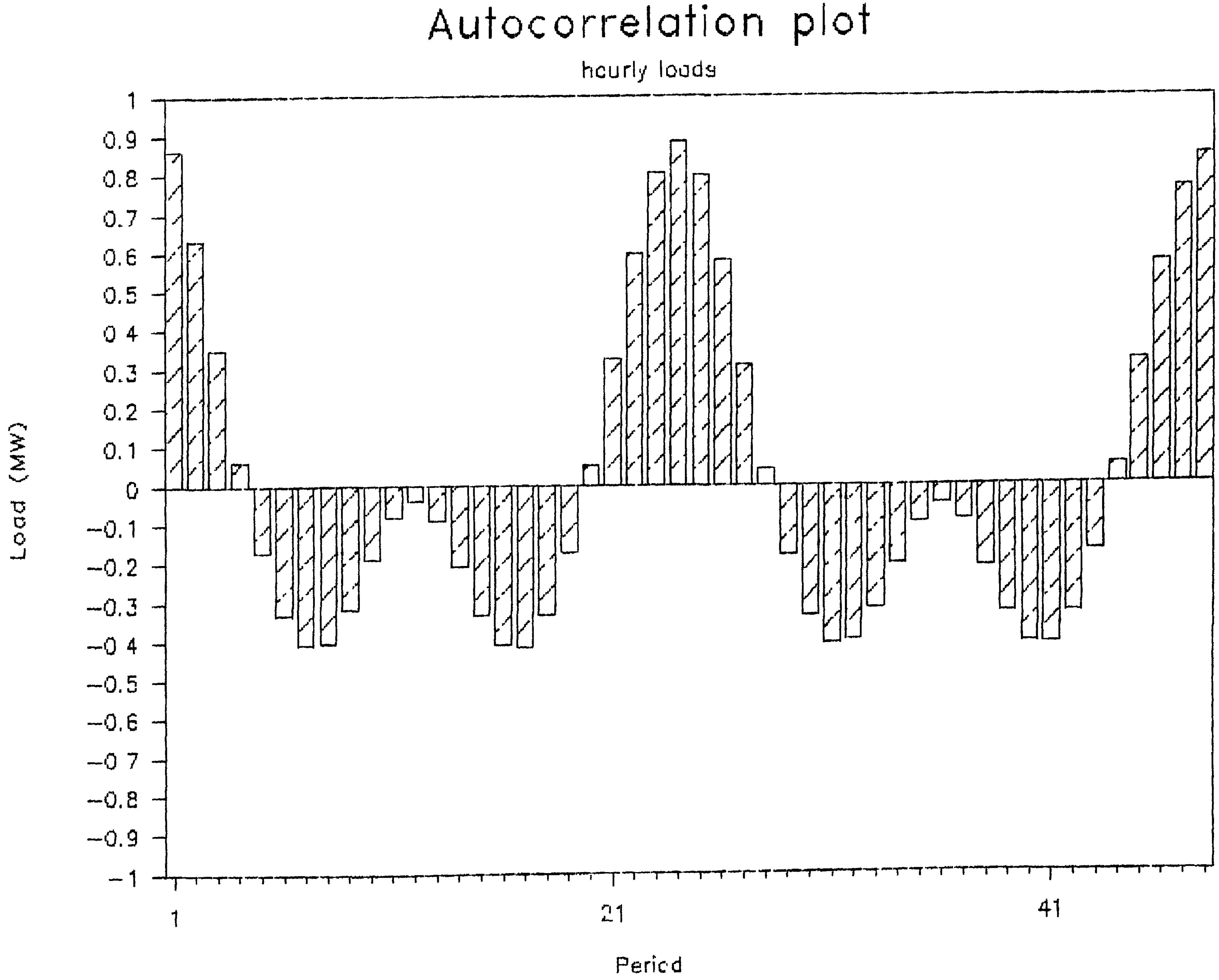


Figure 2



Autocorrelation plot
hourly loads
Load (MW)
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
-0.1
-0.2
-0.3
-0.4
-0.5
-0.6
-0.7
-0.8
-0.9
-1
1
21
41
Period

Figure 3

Observed vs smoothened load

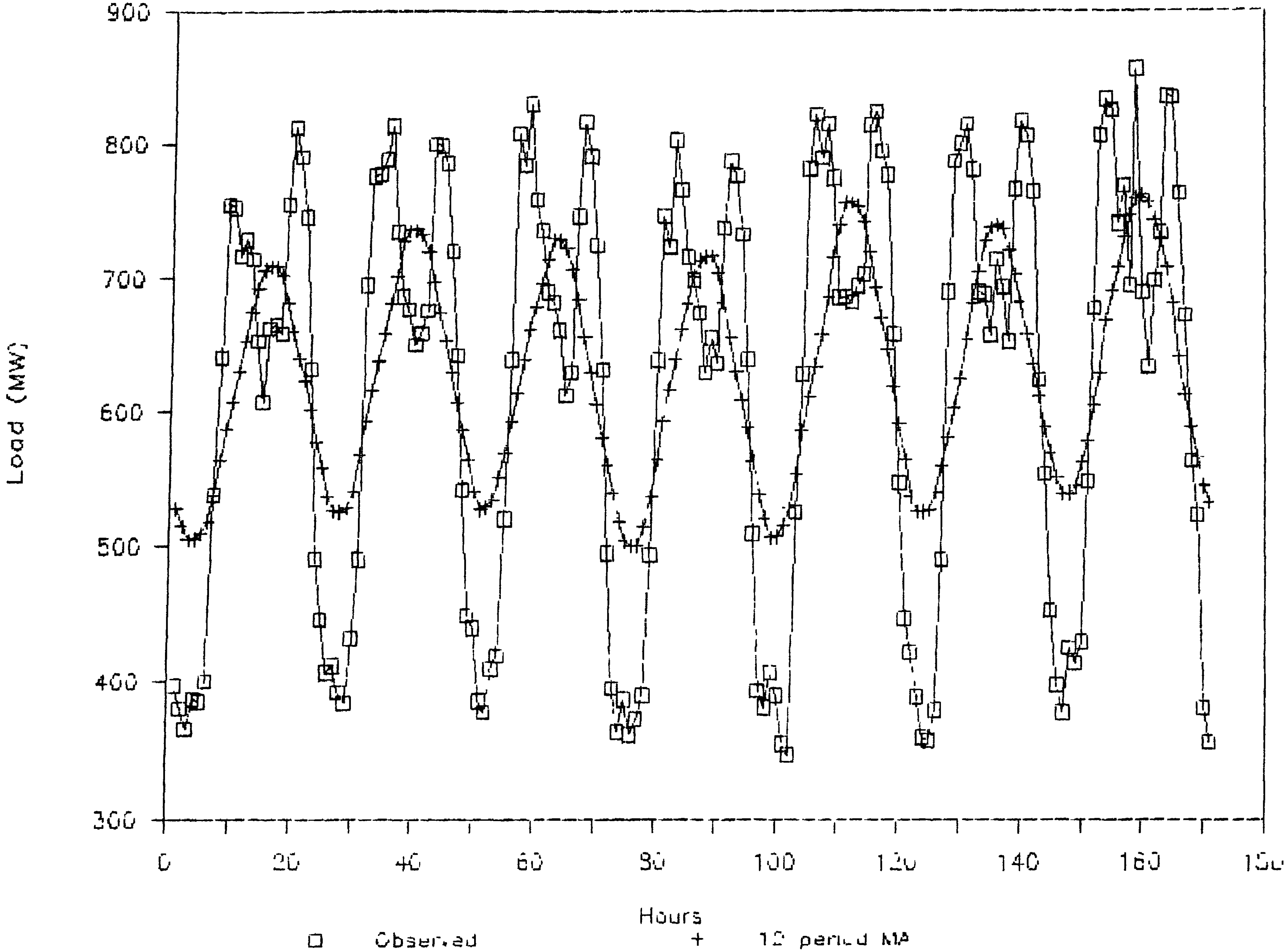


Figure 4

Autocorrelation plot

smoothened hourly loads

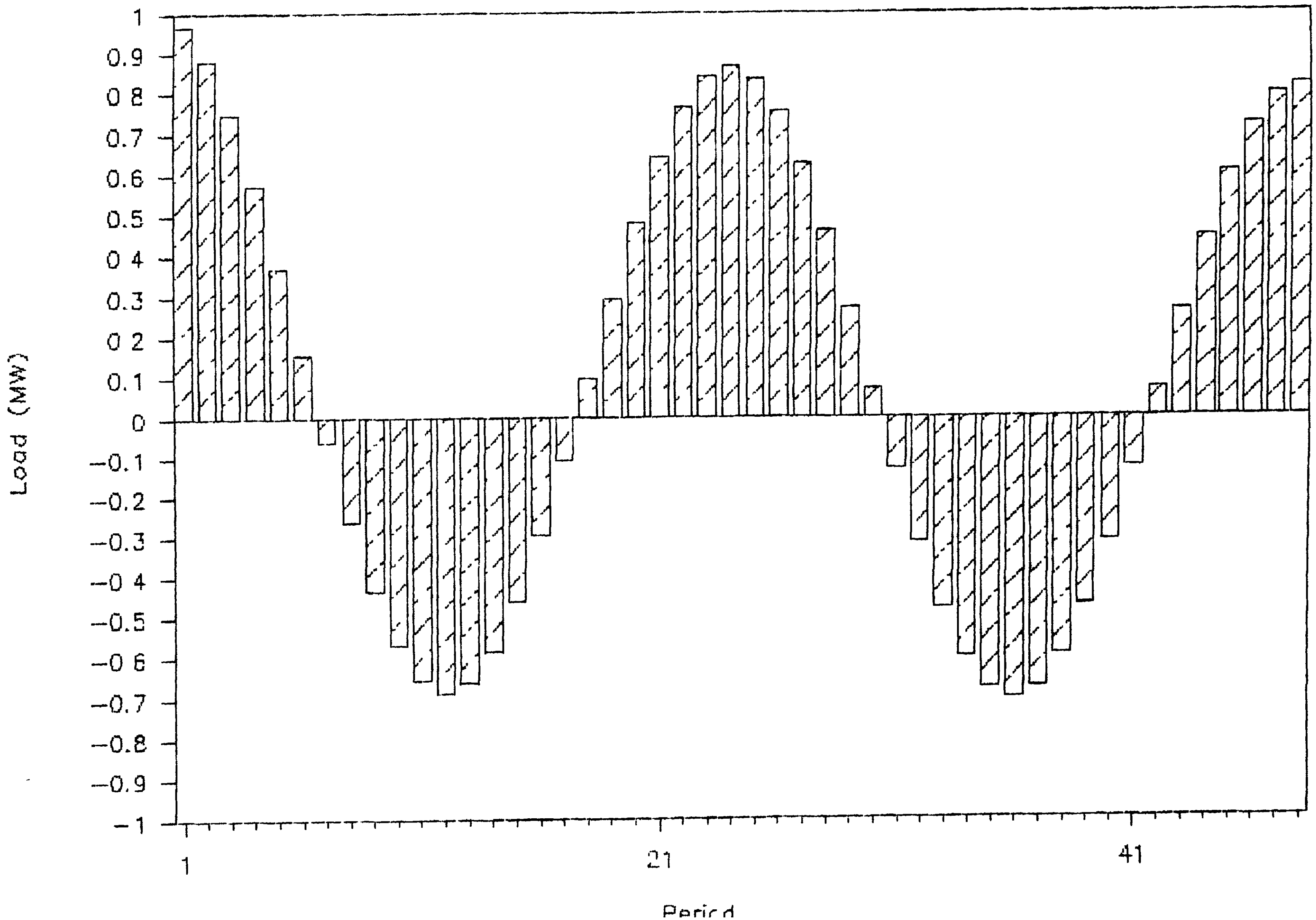


Figure 5

Observed vs predicted load

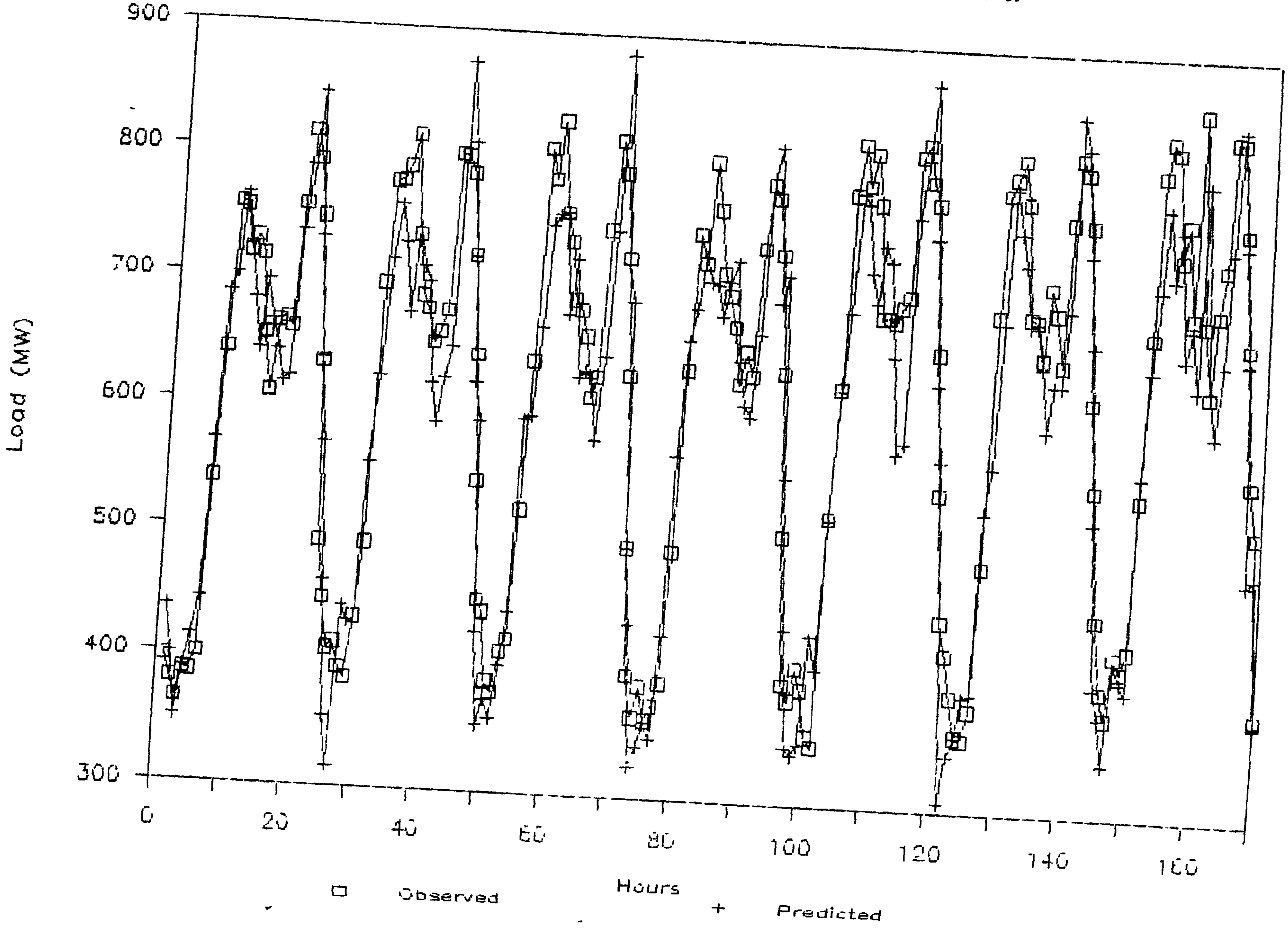
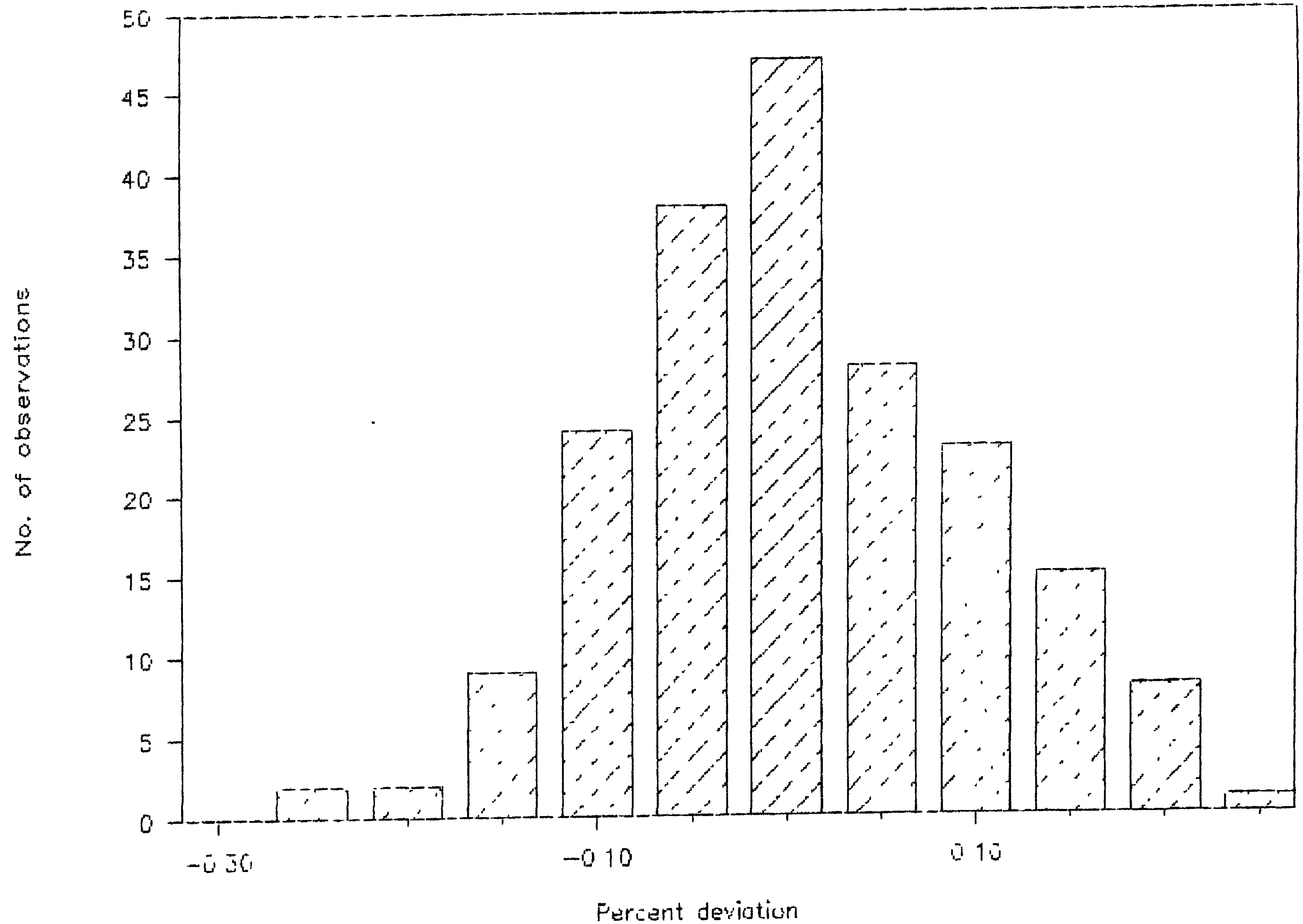


Figure 6

Frequency distribution

Deviation from observed (%)



Changing the Objectives in Electric Utility Planning: An Assessment for Developing Countries

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INTRODUCTION

Over the past twenty years, capacity expansion planning has undergone dramatic changes, both in the concepts of planning, and in the tools available to perform the analysis for planning. The advent of mainframe capacity expansion programs (for instance programs such as WASP, EGEAS, MNI), and their availability to utility planners in developing countries, has ushered in a new era of planning.

Expansion planning moved from a process using simplified tools, and subjective judgement, to one with sophisticated tools and a perception of objectivity. Recently, microcomputer versions of the large expansion planning models have been developed, allowing even more access by utilities in developing countries.

A consequence of the proliferation of these models has been an increasing dependence on the results, and a belief that the results are "accurate". Many planners believe that decisions are less subjective now that these models are being used. This is a myth because many of the input parameters that are used are subjective, and as always, forecasts of demand and price are never 'accurate'.

These models have also become quite complex and large, requiring much data and significant run times. Since only the expert system planner can understand how the results were derived, these tools tend to be considered 'black boxes' by decision makers leaving the decision maker with incomplete information on which to determine future capacity plans.

Even more important are the changes in the purpose of capacity expansion planning. Planning has evolved from solely determining the least monetary cost option, to decisions that also reflect outage costs, environmental degradation, national security, diversity, conservation, efficiency and social considerations.

These have all added to the complex nature of planning in the electric sector, but the analytical tools used for this purpose have lagged behind. Most models still use a minimum cost approach (some include outage costs), but is this the correct objective for utility planners in today's world? This paper will explore some of the changes that have taken place in the planning process, and evaluate how they can be incorporated into the modeling tools currently in use.

CHANGING OBJECTIVES: CASE STUDY OF ASEAN[1] COUNTRIES

Expansion planning in utilities has focused on capacity expansion and has consisted of primarily two decision variables; types of candidate power plants and the length of the planning horizon. Restrictions on expansion include: (a) meeting demand, (b) constraints on the amount of new capacity, (c) constraints on amount of energy, (d) reliability criteria and (e) technical requirements (ESCAP, 1981). Using these criteria, utilities would evaluate the least-cost plan.

However events took hold in the 1980's which made many utilities, especially national government owned utilities, rethink this minimum cost objective. As oil prices went up, many utilities found themselves with over 75% of their electricity generated by oil. (For the ASEAN utilities in 1980, 75% of the generation was by oil, and the remaining mostly

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1) ASEAN; Association of South East Asian Nations includes;
Brunei, Indonesia, Malaysia, Philippines, Singapore, Thailand

hydroelectric). Utilities began to look for cheaper alternatives to match the "least-cost" objective. ASEAN utilities began exploring the possibility of using coal, natural gas and geothermal. Figure 1 shows the expected generation by fuel for ASEAN from the 1984 expansion plans.

Considering only the utility expenses, coal and gas may have been cheaper alternatives in 1980. However, the infrastructure costs needed to develop coal and gas resources could quickly bring the national economic costs of these resources above the costs of generating by oil, even at 1980 prices. Of course with the decrease in prices during the past few years, many of these alternatives are no longer cheaper, even without considering the infrastructure costs. Even so, the utilities still have continued to seek ways to substitute oil-fired generation, which brought a new word into the planning objective; diversification.

Utilities felt the need to diversify so they would not be subjected to continued uncertainty and fluctuations in the oil markets, and should not be dependent on one fuel only. In fact the utilities in ASEAN have put diversification at the top of the list of key factors in expansion planning (Bernstein, Kadir & Kim, 1986).

Going hand-in-hand with diversification is the move towards the use of indigenous resources. In many cases these are not the "least-cost" fuels for the utility, but if one considers the long-term-benefit of the nation, the use of indigenous resources, at least in some part, may be the most cost effective.

Other factors have also entered into consideration, one of the most important being reliability and outage costs. The concern over reliability has surfaced through the recognition that reliable supplies of electricity are necessary for industrial development and investment. Outage costs are explicitly entered into some of the capacity expansion models, but the

estimation of these costs is difficult.

Utilities also use bounds on the Loss-of-Load-Probability[2] (LOLP) as measures for reliability in capacity planning programs. Choosing an LOLP of 1 day/year, as most of the ASEAN countries have done, has an effect on the expansion path chosen by the planning models. In reality however, most of these utilities may face LOLP's of more than 1 day/year, so the expansion path chosen is not optimal. Choosing a LOLP too low means that more capacity is being built than should be under realistic reliability expectations. Therefore the choice of the level of reliability should be incorporated into the planning objective (Munasinghe, 1980).

The LOLP is affected by a number of factors which are interrelated; the capacity size, availability of capacity, and the transmission & distribution (T&D) system. The first two are adequately addressed in capacity planning frameworks, while the T&D system is not. In particular, T&D losses are important because they can be quite high and costly for some countries[3]. Reducing T&D losses can provide substantial savings to utilities (Munasinghe, 1987), and should be part of the optimal expansion path, and the objective function.

Transmission and distribution requirements however, have often been treated as by-products of capacity and demand requirements, and not part of the optimizing variables in system expansion problems In many cases,

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2) Loss-of-load-probability is the expectation as to the average number of days over a long period during which the daily peak is expected to exceed the available generating capacity (APDC,1985)

3) Transmission and distribution losses can range from 15-50% in some regions of these countries. Indonesia had a total 26% losses in 1982, and the Philippines while the total had been about 20%, some portions of the grid have seen losses as high as 40%. A large portion of these losses are associated with the distribution systems, and some may be metering problems in which improvements may not lead to lower capacity requirements, only a better idea how much is being used.

generating capacity and T&D planning are performed separately, with only an information flow between the two. For instance in the "Electric Future" studies for Indonesia and the Philippines (East-West Center, 1985) it is made clear that there are separate optimization models for the two. In fact they say separate models are sufficient. This ignores the tradeoffs that can be made between capacity expansion and transmission & distribution improvements.

Certainly if system losses are reduced, less capacity would be needed and it would change the expansion path. As well, the choice of plants, primarily size and deployment of individual plants, will affect the T&D losses. This dynamic interaction is not captured in existing frameworks. One of the suggestions in the East-West Center report on Electric Futures of the Asia Pacific Region was the need to integrate generation and transmission system expansion models (East-West Center, 1985). To my knowledge, this has not been accomplished but is important for system expansion.

Rural electrification has also been an issue, which may be in conflict with least cost plans. Generally, rural electrification has been buried within regional demand forecasts. Governments generally develop plans to electrify a certain percentage of households, (primarily due to economic development issues), and this target of electrification is an objective for the utility reach in the expansion planning program.

Demand management and conservation are also increasingly becoming part of a utility's planning. If utilities are unable to raise capital to build new plants, while still required to meet demands, conservation must be a part of the expansion plan. For government owned utilities, it is in the governments best interest to promote efficient use of electricity and therefore demand management needs to be considered explicitly as an

objective in the overall plan.

Other new objectives such as environmental concerns may soon be added to the utility planning structure and these should be explicitly related to the objectives of planning.

These objectives, which are already making up some of the planning decisions in these countries, have not been addressed by the major planning models nor are they often systematically included in the planning process. Changes in the concepts of planning have moved faster than changes in the models that are being used to help the decision maker. System planners are often depending on the outcome of these models to provide solutions, but the answers are often incomplete. The decision makers then use subjective judgements to weigh the other factors, but still depend on the results coming from the system planning model as the base case. An understanding of the relationships of these factors and their part on the overall objectives of planning is necessary for the planning process.

The objectives as outlined above are summarized below:

minimize generation costs

minimize outage costs

minimize transmission & distribution losses

maximize efficient demand side use

maximize diversity/indigenous resources

minimize environmental impacts

There are a number of ways to find the optimal path with these objectives. One is to combine these into a single objective function, relating each individual objective to costs, and having the program minimize the sum of all the costs. This is perhaps the simplest solution considering existing planning systems.

Another way is to convert the objective to "expected utility" of the decision makers rather than to costs (Noland, 1988). This is much more difficult and subjective, but allows decision makers to recognize their value tradeoffs explicitly.

A third way is to consider a goal programming approach which would require major changes in existing planning models and may be infeasible in the short term in most developing countries. Therefore in this analysis I will concentrate on the first approach.

SYSTEM EXPANSION PLANNING MODELS: THE OBJECTIVE

Capacity expansion computer models frequently called "System Expansion Planning Models" have been used in developing country's electric utilities for a number of years. These models, such as WASP (International Atomic Energy Agency - IAEA), EGEAS (Electric Power Research Institute - EPRI) and MNI (Electricite de France - EDF), are primarily focused on generation expansion.

These models have been used to evaluate the "optimal" expansion path for electric utilities, given some input parameters supplied by the user. The major models are based on mathematical programming to solve for the "least-cost" path These models take into account the technical factor of existing and new systems, incorporating demand forecasts, system characteristics, and choosing between a large number of possible expansion paths to find the least cost path.

Since the WASP model is most widely used in the developing countries, this paper will focus on the characteristics of that model, specifically on the objective function. Once the basic data is developed, the WASP model finds the "best" expansion policy, which means finding the expansion path with a desired reliability and minimum discounted cash flow expenditures

(IAEA, 1984). The model uses dynamic programming to solve for the least cost path.

The objective function is set up to minimize cost including a measure for the cost of outages. The function is as follows:

$$\text{Minimize Total Costs} = \sum_{j=1} [C_j - R_j + OC_j + CSTENS_j]$$

where C_j = Capital cost

R_j = Salvage cost

OC_j = Operating costs

$CSTENS_j$ = Cost of Energy not served

$$\text{and} \quad CSTENS_j = [c_1 + c_2 * (\frac{Es}{EA_j}) + c_3 * (\frac{Es}{EA_j})^2]$$

where c_1, c_2, c_3 are coefficients for energy not served in \$/kwh

Es is amount of energy not served

EA is energy demand

Constraints include demand requirements, supply availability, capacity limitations, transmission losses, and reliability considerations. "Tunnel limits" are set for maximum and minimum levels of capacity in any given time period, and for limits on reliability.

RELIABILITY AND PLANNING

One of the first papers to recognize the need to add reliability into the planning framework was done by Mohan Munasinghe in 1980. Munasinghe's work on a "New Approach to Power System Planning" introduced the concept of using a reliability optimization as opposed to a system cost optimization. The argument centers on the issue of choosing optimal reliability levels.

currently planning is performed to find the minimum cost which satisfies demand, within some reliability bounds. The choice of reliability bounds are based on some historical rules-of-thumb. The difference to the consumer of facing a loss-of-load-probability of 1 day per year, or 3 days per year may go unnoticed, however the impact of this on capacity requirements for peak and spinning reserve may be great.

In his seminal piece, Munasinghe develops a theoretical model in which the supply costs are compared with the worth of reliability. The optimized power system is one in which the net social benefits are maximized (or equivalently the costs of outages plus the cost of supply is minimized). Figure 2 reproduces the graph from the article, and shows the relationship between costs and reliability. As reliability increases, outage costs (OC) decrease, while supply costs (SC) increase at high levels of reliability. The total costs (TC=SC+OC) decrease as one moves from the lower levels of reliablity and then increase dramatically as the reliability levels reach the maximum. The optimal reliability level is therefore R^*, and the expansion plan should be set to this level. Munasinghe has expanded this work and developed an optimizing model which optimizes system investments and operations to where marginal benefits achieved from an improved generation supply quality are offset by the costs.

This approach is theoretically pleasing, and has advantages for national planning, however the existing planning models are not equipped to handle this analysis. Most planning departments would not easily change from their existing planning tools and structure as well.

Another issue is the estimation of the outage costs. Further work needs to be done in estimating these costs. A special issue of the <u>Energy Journal</u> (1988) includes a series of papers which shed some light on the

problem. The analysis still requires more data and effort than is reasonably available in many developing countries.

As mentioned above, the WASP model includes in it's objective function a value for outage costs, however the function is quite different than that developed by Munasinghe. The optimizing variable is the capacity required to meet demand at minimum cost including outage costs. These are evaluated within some 'tunnel' restrictions on reliability.

The outage cost is a function of the percentage of energy not served per total demand. The functional form is quadratic, and the coefficients are defined by the user. For the outage cost to have any meaningful impact on the minimum cost solution, the coefficients, (which reflect the cost per kwh of outages), must be very large. The independent variable (percent of energy not served) is a small number, and if the input costs per kwh outage are too low, this cost of energy not served will not have any impact on the optimal solution. However, many utility planners are reluctant to use outage cost figures high enough to have any impact on the optimal solution.

The optimal solution is also sensitive to the choice of these coefficients and figure 3 shows a number of possible outcomes. The graph depicts a slice-in-time of the expansion plan. In any given time-frame a choice is made as to how much capacity to bring on line within reliability limits. In this example, at the lower reliability limit (for example LOLP of 3 days per year), capacity in the amount of P1 MW is needed, while at the high reliability limit (say 1 day per year), P2 MW is required. The supply cost associated with this is the SC curve. and the outage, or cost of energy not served costs (OC) is also represented.

If the curve is steep (figure 3a) then the minimum cost may occur somewhere between the two limits, producing a meaningful minimum cost solution. If the curve is relatively flat (figure 3b), then the lower

capacity point will be chosen.

Most system planners have not recognized the importance this may have on the planning decisions and unless realistic estimates of outage costs are used, they will not have much effect on the planning decisions. While reliability is still an objective, unless the choice of costs is carefully evaluated, it may be best that the outage cost remains underutilized.

TRANSMISSION & DISTRIBUTION

In his original 1980 piece, Munasinghe discusses extending the reliability optimizing approach to transmission and distribution planning, explaining that the major cause of outages occurs in the T & D systems. However, the issue of how to estimate the outage cost exists whether one discusses T&D or generation. One can measure T&D performance in a number of ways, one of which is the efficiency (or losses).

While measuring efficiency as opposed to reliability is not the same, using efficiency as a measure in the objective function would be more acceptable to system planners because it is a number that can be easily understood. Also calculating the costs of improving transmission and distribution efficiency is by far simpler, and more concrete than outage costs. This makes it easier to insert into existing planning structures.

The objective function would then become the minimization of supply costs <u>plus</u> the expenditures to improve T&D efficiency. These two will provide tradeoffs, since improving T&D efficiency will mean less capacity is required to meet the same load. Using a similar approach as in the outage cost section, Figure 4 shows a portion of the planning horizon. To meet a particular load and reliability criteria, the system will require P2 MW if no improvements are made in the T&D system. On the figure are a supply curve and T&D cost curve (including investment and operation). As

improvements are made in the T&D system (moving from right to left), less capacity is required to meet the load and the costs of T&D rise, while supply costs decline. Then one can calculate the total costs and find the optimal mix between capacity and T&D improvements which minimizes cost.

This can be included in the capacity planning models just as the outage cost is, using a function where the transmission & distribution costs are a function of percent transmission loss improvement. For example:

$$\text{Extra T\&D Costs} = a + b[\Delta \%\,\text{loss}] + c\,[\Delta \%\text{loss}]^2$$

$$\text{where } \Delta \%\text{loss}_t = \%\,\text{loss}_{t-1} - \%\,\text{loss}_t$$

If there is no change in transmission efficiency there is no 'extra' cost associated with T&D other than that required to meet load requirements, however if losses decrease, there will be added costs over and above the minimum requirements.

This will be more acceptable to planners as a way to include transmission concerns into the planning structure The importance of improving T&D efficiency is increasing as funds for investment capital are declining. Providing this direct tradeoff between capacity investments and T&D investments is necessary for successful long term operations of the utilities.

Transmission losses of 30 or 40% are unacceptable, and methods for improving effciency, ranging from increasing transmission line size, to upgrading equipment, to improving security and metering on transmission and distribution systems, are feasible. Decisions on T&D improvements need to be made within the context of generation system planning and not as a separate entity.

DEMAND-SIDE EFFICIENCY: CONSERVATION

As a national government owned entity, a utility should be involved in conservation activities which can provide more efficient services, and in the long run keep the utility financially secure. Conservation can be a part of the planning structure since investments in conservation, which traditionally require less capital expenditures, might delay investments in new capacity. For utilities in a cash-poor position, this added time may be enough to accumulate funds for expansion.

However, in the planning process, conservation is thought of as part of the demand-side analysis. In the ASEAN electric future reports, conservation is relegated to a few pages in the section on demand forecasts. But conservation is not neccesarily a demand-side issue. If the utility is to invest in conservation as a way to delay the building of a more expensive power station, then conservation becomes a supply issue. In fact the tradeoffs between capacity and conservation are similar to the relationships between capacity and reliability, and capacity and transmission.

In common practice some estimates of conservation are made and the 'energy saved' is subtracted from the load. Another way to view conservation is that if investments are made by the utility in conservation, less capacity would be required to meet load, thereby treating the energy saved as 'equivalent capacity'. This allows for tradeoffs between investing in conservation or investing in capacity. In otherwords, what is the optimal mix of investments in capacity and conservation?

One can estimate the relationship between investments in conservation and energy saved. This is more difficult than transmission estimations, but not as difficult as estimating outage costs. Investing in conservation

equipment, insulation, and more efficient appliances create direct benefits and are easily approximated. The impacts of educational and promotional programs are more difficult to evaluate but estimates can be made. The relationship between supply cost and conservation investment is similar to the T&D case (figure 5), and an equation can be developed using the cost of conservation as a function of the energy saved (quite similar to cost of energy not served function).

The importance of this proposal is the change to be made in how planners view conservation. Instead of conservation estimates being subsumed in the demand forecasts with arbitrarily chosen conservation levels, planners should include it in the objective function, and choose the minimum cost system which optimizes capacity and conservation.

Ideally of course we would also add to this the cost of T&D improvements as outlined above, and find the optimal path which minimizes costs along all three dimensions.

Figure 6 shows one possible example. If conservation and T&D improvements are made to their maximum, P1 MW are required, while if neither is done, P2 MW is required (there are variations in which one could consider a maximum amount of conservation, but limited T&D, however this graph shows one possible example for illustrative purposes). In this case the optimal system costs, are a combination of supply, conservation and T&D costs, but the existing planning models, and existing planning frameworks do not pick this up. Any variations to expansion plans due to improvements in efficiency (whether demand-side or T&D) are done ad-hoc without creating the proper tradeoffs. What is the proper combination of capacity, conservation and T&D improvements? Without some formal process to evaluate it, the plans are guesses at best. By adding the objectives outlined here,

these decisions can be more systematic.

DIVERSIFICATION

The issue of diversification is more complex, and much more difficult to quantify than all the previous objectives. First we must define what diversification should mean. The ASEAN utilities have made diversification a high priority, but the actions they have taken do not reflect this. The utilities have not as much had a diversification policy as much as an oil-substitution policy. The expected fuels used to generate electricity by the ASEAN utilities, show that oil will make up a small portion of the total generation beyond the year 2000 (Figure 1). For some countries, no oil-fired generation is expected to be used at all. The replacement fuels are either gas or coal so that in reality the utilities have not been diversifying.

However, diversification can still be a good policy, and in the long run provide enough flexibility for the utility to weather short term fluctuations in prices and supply. Diversification may be included in a number of ways. In a planning sense it is often left to the strategic decision makers to make some determination as to the types of fuels which would be the best mix, and determine some minimum levels for each fuel.

Currently the plans for LLN in Malaysia are to eliminate all oil-fired generation, replacing it primarily with natural gas. This leaves the utility vulnerable to short term supply shortages (for instance problems with the gas pipeline), and they could have planned to leave some oil-fired generation available. The decision makers must have determined that the risk was not great enough, but how was the determination made, and was it done systematically, with proper information?

This ad-hoc procedure is not very satisfactory in light of the other

objectives outlined in this article. One could include decision analysis techniques to determine the judgements and preferences of the decision makers, and quantify those beliefs (Keeney, 1980). This could provide a measure for diversity, and would quantify the risks the decision makers would take to rely on one fuel only. Decision analysis tools however, can be time consuming and outside the normal purview of most system planners. This is not to say it shouldn't be done, only that it will not be easily accepted.

Another way would be to a priori, set a 'penalty' cost to any fuels when they are not used at some minimum level. As the fuel use declines below this level, then the 'penalty' cost would go up. This provides cost curves similar to ones developed for the previous objectives Unfortunately, the magnitude of the costs, and the cutoff points are - - subjective, and still depends on the risk averseness of the decision makers.

Lastly, one could use multiple runs of the capacity planning model using different sets of inputs by first finding the optimal path with no restrictions on fuel, and then restricting fuels to a minimum level. The decisionmakers can then compare the cost of these and determine whether they are willing to pay the increased cost associated for the diversification, or take the risk of fuel supply disruptions, or price fluctuations.

In this case the decision maker may require some quantitative assessment of the risks associated with supply disruptions or market fluctuations. Even though the decision maker probably has some preconceived ideas about the risks, an assessment of the risks would be important for the planning process. For instance, an evaluation of the impact on the

utility and economy of Malaysia of a natural gas supply disruption would give the decision maker values to weigh.

This method would be the most effective, because it provides concrete numbers for the decision maker to compare. With the advent of the PC based models it is easier to perform multiple analyses than with the mainframe versions and therefore scenarios can be run and compared.

It can be argued at this point that the choice by the decision makers may not be 'optimal', especially since this paper has tried to explicitly define all the objectives for the optimization. There are methods which can quantify all these, but at some point the quantifications will end, and some judgements will be made by those making the choices. The intention here is to limit the 'ad-hoc' procedures while not creating too many complex studies, and to present information so the decision maker can make an informed decision.

PRACTICAL APPLICATION AND CONCLUSIONS

This paper presents a number of ideas that are important for system planning activites. The major concepts are the inclusion of some planning issues as objectives in the planning structure, and the place these objectives have in the planning hierarchy.

As we saw, current objectives go beyond the classical minimum supply cost objective and have moved to include reliability, transmission and distribution, conservation, and diversification. This will force changes in the way system planning is done, but the changes do not have to be dramatic and can be incorporated in existing planning structures.

In the past Transmission and Distribution were divorced from generation expansion planning and it needs to be incorporated. Also investments in conservation, can be thought of as supply-planning issues

and should become part of the capacity planning procedures.

These ideas can be easily incorporated into system plans, without creating large new models, and without major overhauls of planning departments. As a first approximation, one can run scenarios with the models, inputting specific characteristics. One first creates feasible cases for a series of transmission improvements, conservation programs etc. The models are then run using these specific characteristics and the costs of achieving the objectives are added and compared across runs. This does not provide the true tradeoffs, but it will provide a range of solutions which takes into account the concerns outlined here.

Most of these ideas can also be added to the section of the WASP model that calculates the outage cost. One needs to come up with coefficients for the function that relate to the objective being measured.

It is also possible to create a separate submodel which would interface with the WASP model output at each iteration The submodel would take the minimum and maximum capacity levels (as shown in the examples), and calculate the optimal mix of transmission efficiency and conservation, then return this solution to the model to run for the next time period. While this is feasible, it will create some major computer programming problems.

These issues are very important in planning future utility systems. We must be aware of the tradeoffs, and recognize the issues that are facing utility planners. The planners and decision makers need to work together to develop a planning structure that will incorporate the objectives of the decision makers in a more formal process. This way decisions are consistent, and justifiable.

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GENERATION BY ENERGY SOURCE

ASEAN TOTAL

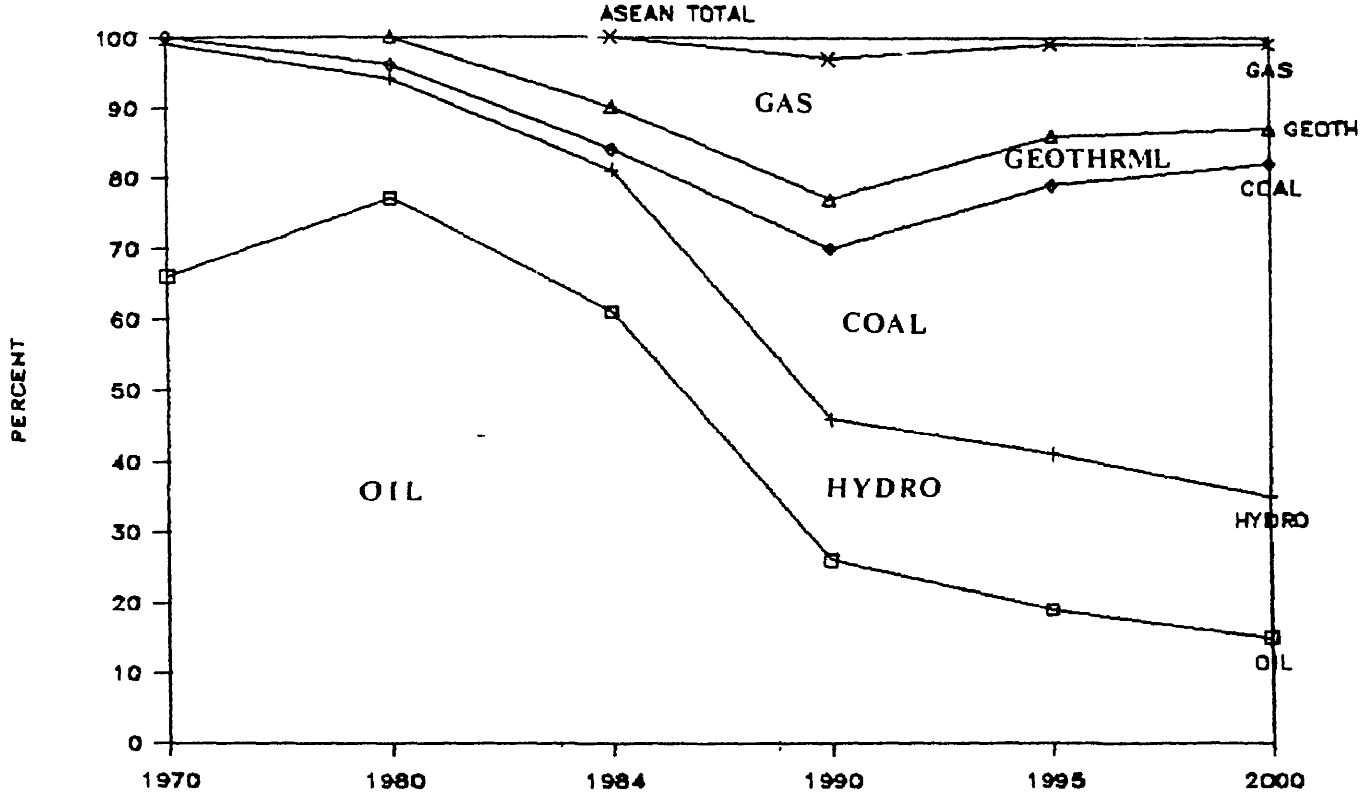
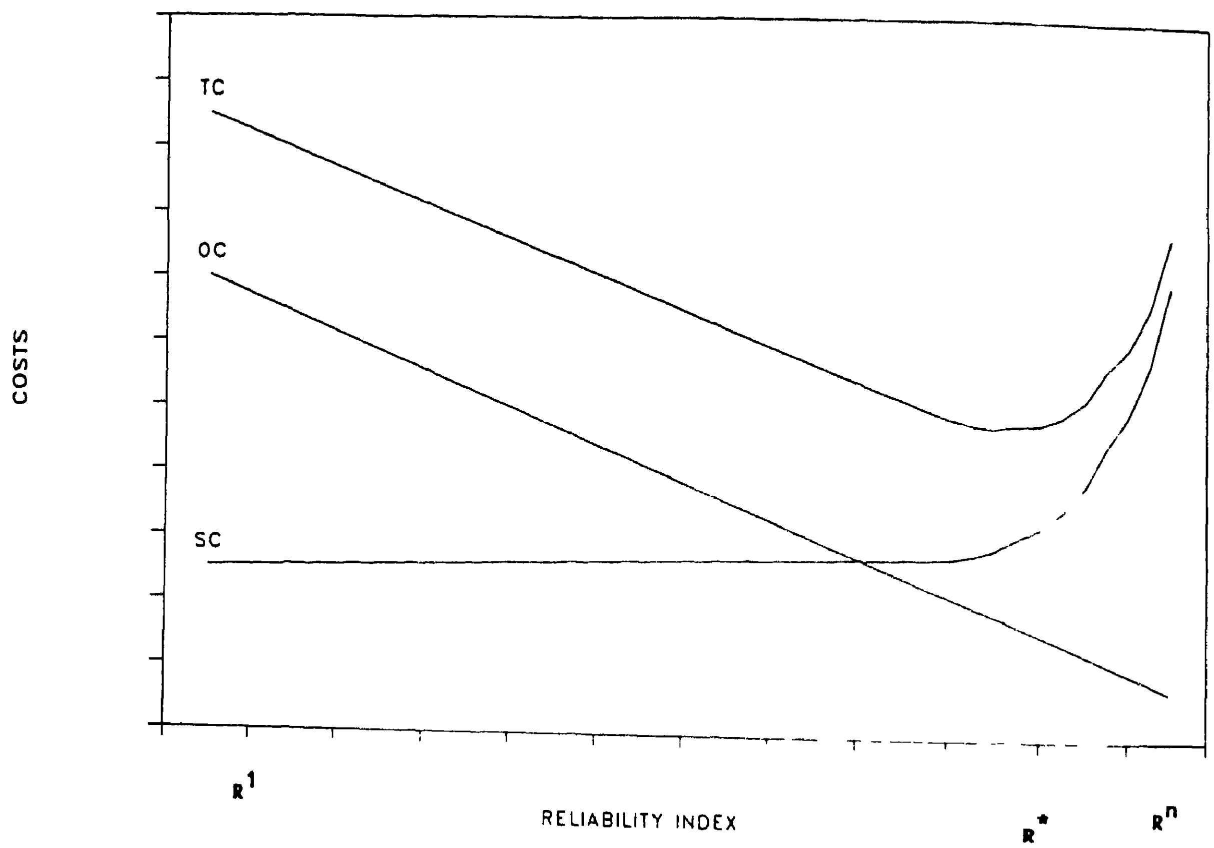


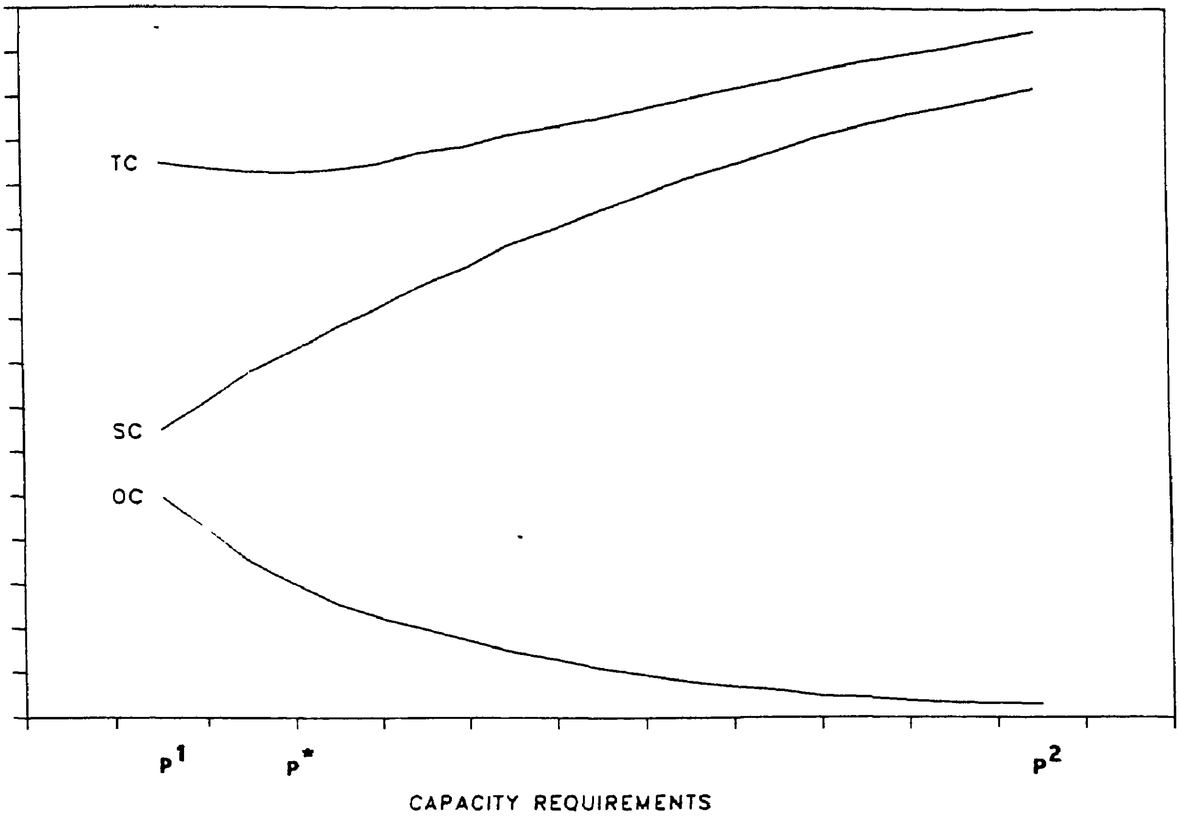
FIGURE 1

FIGURE 2



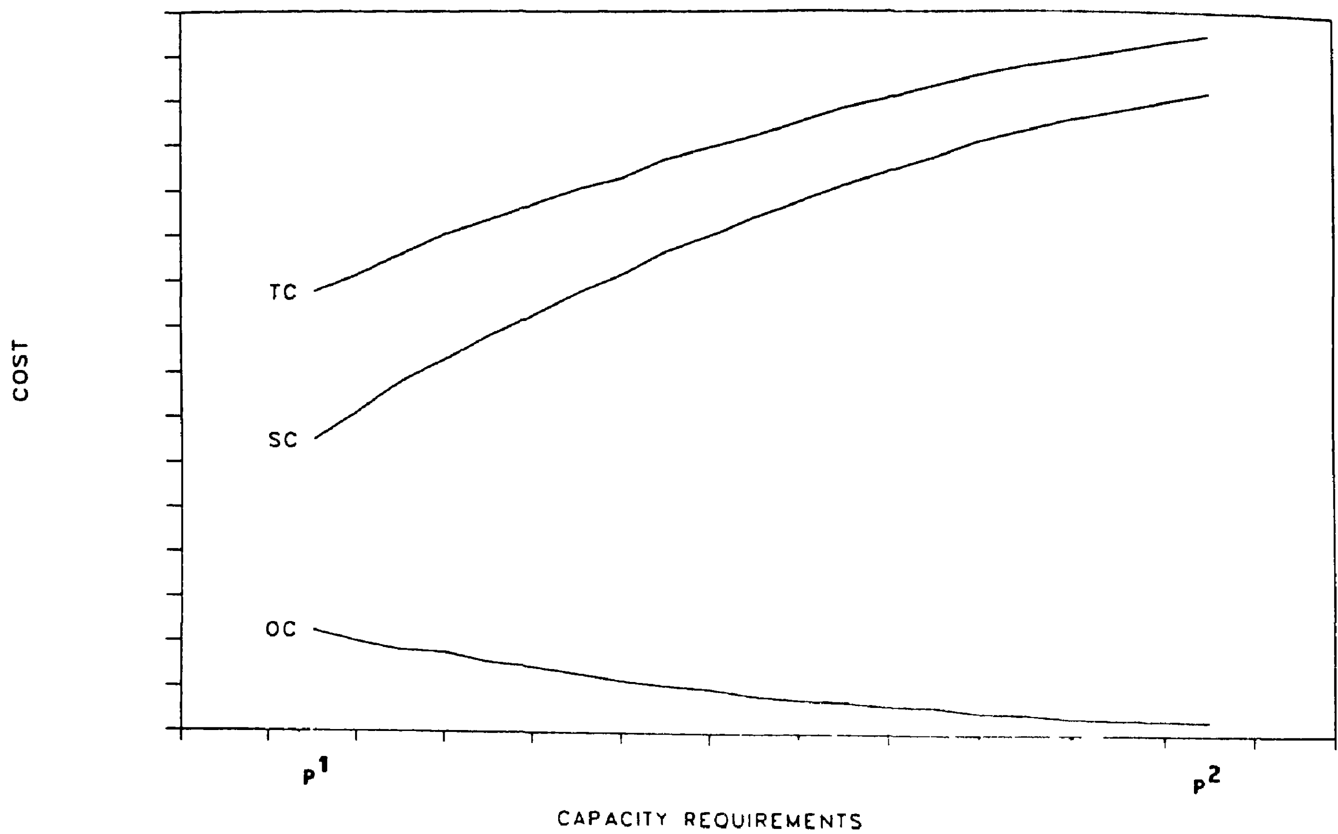
OUTAGE COSTS (OC), SYSTEM COSTS (SC), TOTAL COSTS (TC)
PLOTTED AGAINST RELIABILITY INDEX
(FROM MUNASINGHE, 1980)

FIGURE 3A



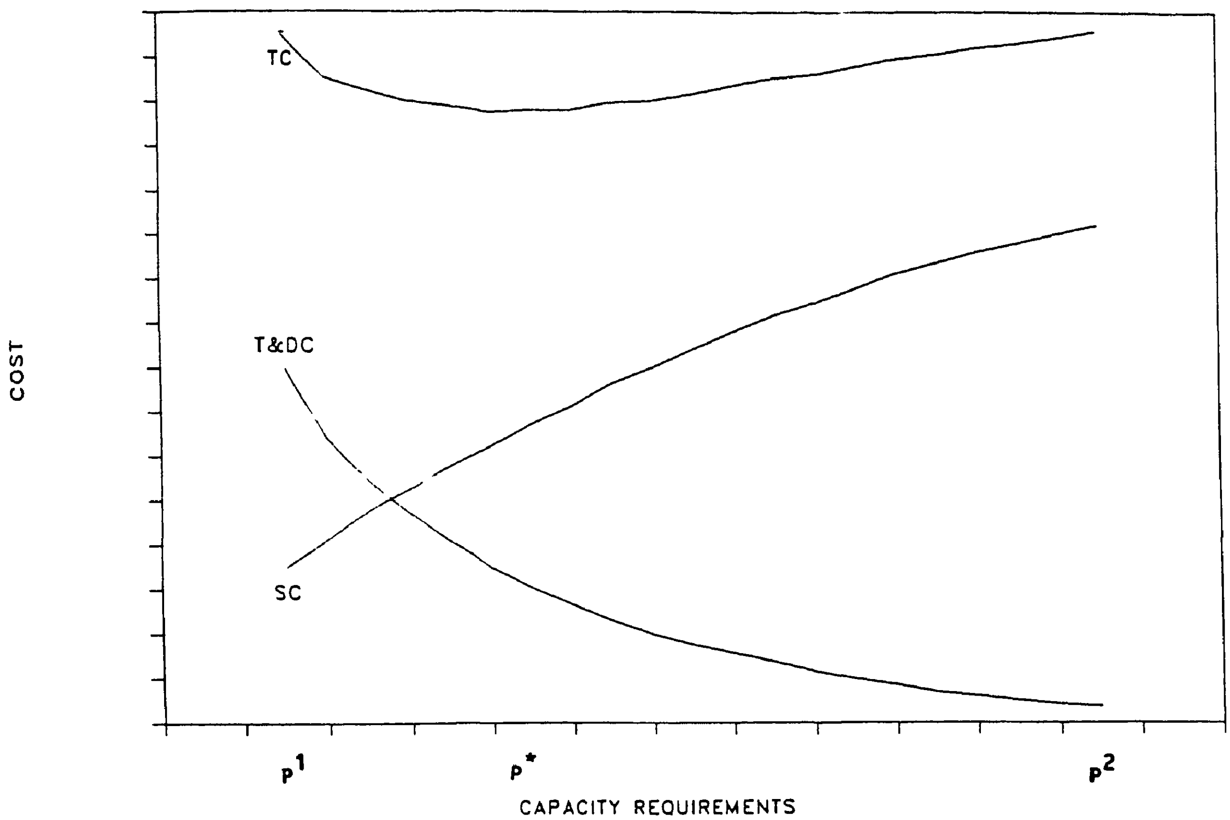
SUPPLY (SC), OUTAGE (OC) AND TOTAL (TC) COST CURVES
FOR GIVEN CAPACITY & RELIABILITY LIMITS

FIGURE 3B



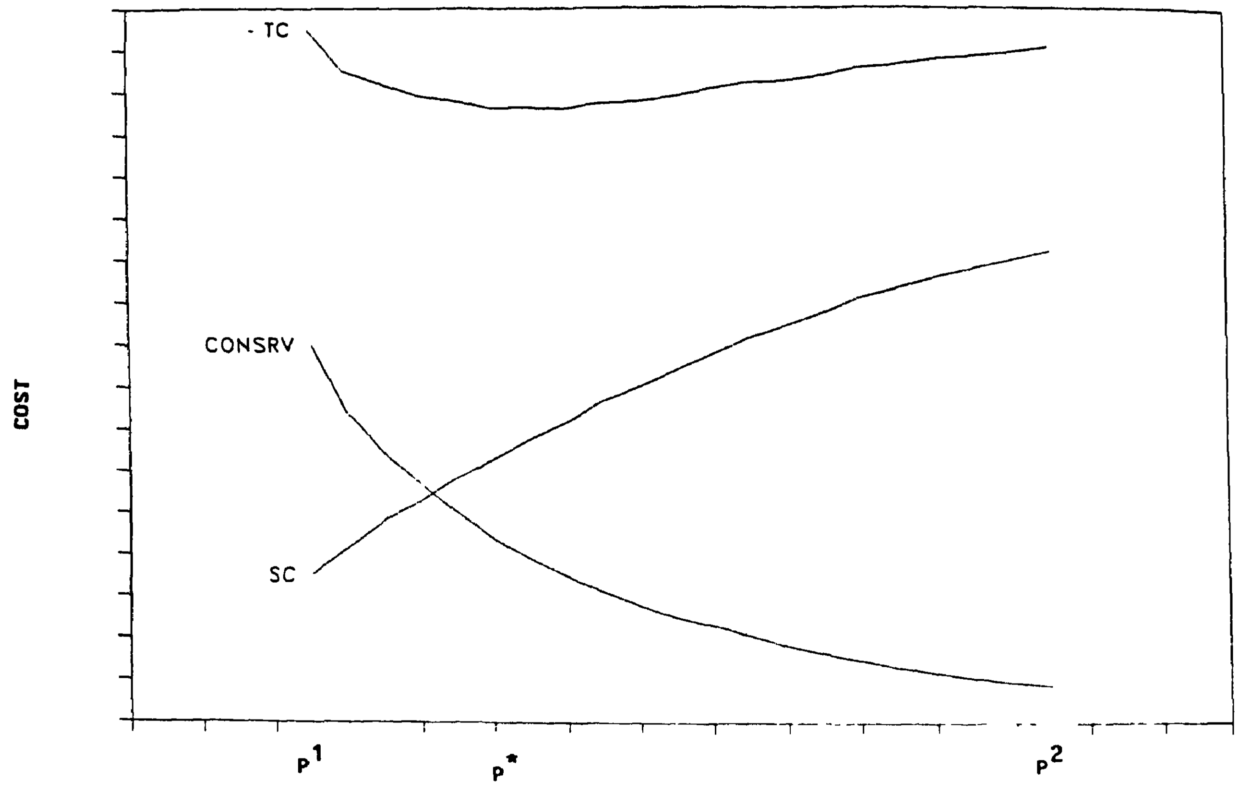
SUPPLY (SC), OUTAGE (OC) AND TOTAL (TC) COST CURVES FOR GIVEN CAPACITY & RELIABILITY LIMITS

FIGURE 4



SUPPLY (SC), T&D (T&DC) AND TOTAL (TC) COST CURVES
FOR GIVEN CAPACITY & RELIABILITY LIMITS

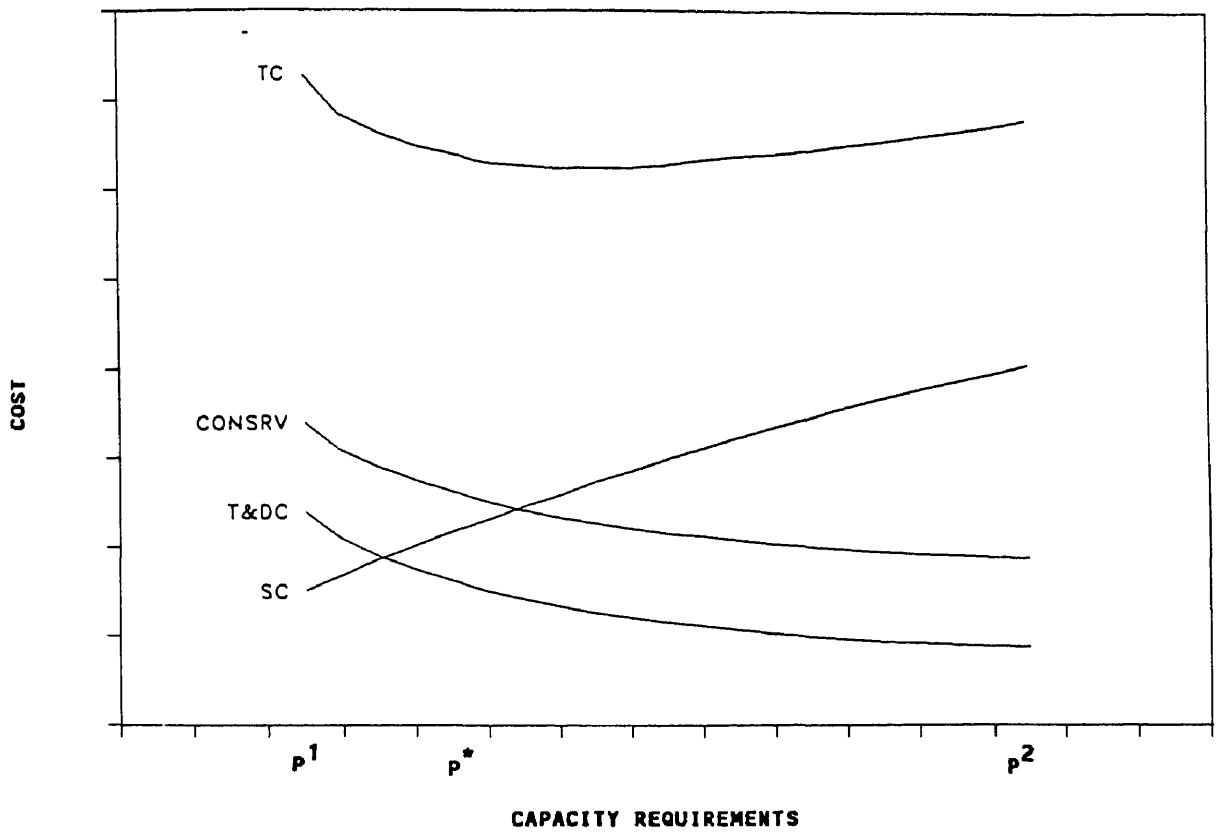
FIGURE 5



CAPACITY REQUIREMENTS

SUPPLY (SC), CONSERVATION (CONSRV) AND TOTAL (TC) COST CURVES
FOR GIVEN CAPACITY & RELIABILITY LIMITS

FIGURE 6



SUPPLY (SC), T&D (T&DC), CONSERVATION (CONSRV)
AND TOTAL (TC) COST CURVES
FOR GIVEN CAPACITY & RELIABILITY LIMITS

Technical Appendix on Electricity System Expansion Planning Models'

Introduction

An economic 'model' represents a simplified form of a real life situation. An attempt is made in a model to study the interrelationships of a number of parameters or variables, which, by their interaction, meet certain desired objectives or ends in a certain time-frame. Generally, these relationships are expressed as behavioural and mathematical equations. There are several well-known macro-economic models which depict the aggregate relationships in the entire economy, but the concern of this Appendix is with electricity system expansion planning models.

An electricity system model is obviously a sub-model of an overall energy model, but it is desirable to deal with it separately in view of the complexities of this sub-sector. The process of assessing future energy (including electricity) needs and the determination of an 'optimum' economic plan of action to meet these needs in the prescribed time-frame, form the core of the energy (and electricity) models. The demand for energy, being a derived demand, ultimately depends on economic growth in varying consuming sectors. Electricity demand is one of the major components of the demand for energy, which includes other forms of energy such as petroleum products and non-conventional sources of energy such as biogas, solar, etc. Planning for the electricity sub-sector is therefore an integral part of planning for the energy sector. In this sense, a power system model is a sub-model in the energy modelling[1] process, which has been adequately dealt with in Chapter 5.

Electricity planning for a system of limited proportions is a relatively simple exercise, as the planner has before him a limited number of alternative expansion possibilities. The comparison of these alternatives can be done manually, though the process takes considerable time. In most contemporary national electricity systems, however, complexities have increased as the systems have expanded. The types of available generating units have multiplied, and include various types of gas turbine, nuclear, combined cycle, base or intermediate fossil-fired, hydro-electric (run-of-the-river type as well as storage reservoir type as part of a multi-purpose project) and pumped storage units. Under each category, several unit sizes exist, with differing terms of technical performance and attendant

1 *It must be noted however, that the use of electricity system models in integrated energy planning need not necessarily be conditional upon the use of models of similar complexity for other energy sub-systems. In fact, for certain energy sub-systems, notably traditional energy sub-systems, one may not employ any 'model' (in the strict sense) due to factors like inadequate data, difficulties in establishing clear inter-relationships among variables, etc.*

implications for unit and overall system reliability and costs

The complexity of electric power systems, the varying technical characteristics of different types of generating units and the concern of the planner for probabilistic treatment of some of these variables have led to the introduction of computer-based models to provide answers to the problem of optimising capacities (and types) to be installed during the given time-frame and the location and timing of their installation These models obviously cannot contain all the variables that have a bearing on the investment planning process [2] The results offered by such models require to be analysed by the planner, whose experience and qualitative considerations must be used to produce a feasible programme of action It may be mentioned here that the models described in this Appendix basically deal with *expansion* planning, assuming a running system to which additions are planned in order to meet increasing power requirements in the coming years

The objective of any expansion planning exercise is to maximise net benefits to the economy, i e , maximise the difference between benefits and costs within a given time-frame The usual approach adopted in the generation planning optimisation exercise is to assume that benefits (namely, the power produced to meet the economy's anticipated demands in the given time-frame) produced by different alternative expansion patterns, are equal Thus, the net benefit maximisation process is reduced to a cost minimisation exercise where the objective is to minimise total system costs The objective function in this approach includes both investment costs of new plants added during the planning period plus system operating costs Since cost streams of alternative expansion programmes will be different, the present-worth criterion (present valulated at an appropriately chosen discount rate) is used to compare these in order to arrive at the least-cost investment programme

Several models are described in this Appendix The Wien Automatic System Planning Package (WASP) is described in some detail, with a step-by-step description of each of the modules This package is available at several developing countries It has many features, such as dynamic programming, probabilistic treatment of forced outages, etc , which make it a worthwhile model to study as many of these features appear in other models as well

2 *For example, organisational and management factors, though undoubtedly important, cannot generally be captured in a model*

2 The WASP model

WASP is composed of six
modules A modular approach allow
interact with the machine step by step
save computer time by correcting err
at each stage

The six WASP programme modu
follow

(i) *Fixed system programme (*
outlines the status of the power syst
start of the study, including firmly
additions, retirements and their sched
of commissioning

(ii) *Variable system programme (V*
describes the type of expansion candi
during the study period Units are diff
by type and capacity (e.g , 1,000 MW
unit, 600 MW nuclear unit, 210 MW
thermal unit, and so on) The data re
define a candidate, namely, number of
units, minimum/maximum capacit
associated heat rates, fuel type, fuel costs,
outage rates and maintenance requireme
the same for both FIXSYS and VARS

(iii) *Load description programme (LO*
defines generation requirements in each
the study For example, the study ma
twenty-five years, and each year may
divided into four periods (quarters
duration curves/forecast peak loads, an
for each such period in this programm

(iv) *Expansion configuration gener*
gramme (CONGEN) allows the user
constraints such as minimum and m
reserve requirements or minimum
number of units of any expansion candi
installed in any given year This pr
incorporates a list of all allowable state
year of the study

(v) *Merge and simulate pr*
(MERSIM) incorporates a pro
simulation model which calculates th
operating cost Reliability is also esti
the probability that the system will not
meet the peak load There is provisi
programme for calculating the c
expenditure separately in local/foreign

(vi) *Optimisation programme (DY*
this programme, a dynamic pro
algorithm is used to determine the opt

.) system expansion policy from the allowable es listed in CONGEN Configurations ing poorer reliability than a pre-defined ical loss of load probability (LOLP), will be itted as non-feasible states When the solution been worked out, this programme will also orm the user if any of the CONGEN trictions has in fact constrained the solution, which case that particular constraint can be odified and a new optimum solution worked t

Both WASP II and its later version, WASP , are employed in many developing countries e basic structure of the two packages is oadly similar, the essential differences lying in e treatment of hydro-electric capacity In the llowing discussion, WASP II is described first, llowed by some observations on WASP III, herever necessary

An overview of the linkages between the six mponent programmes of WASP II is shown in o parts in Figures 13A-1 and 13A-2 The gnificance of the linkages can be better derstood after following the subsequent tailed discussion of the various modules

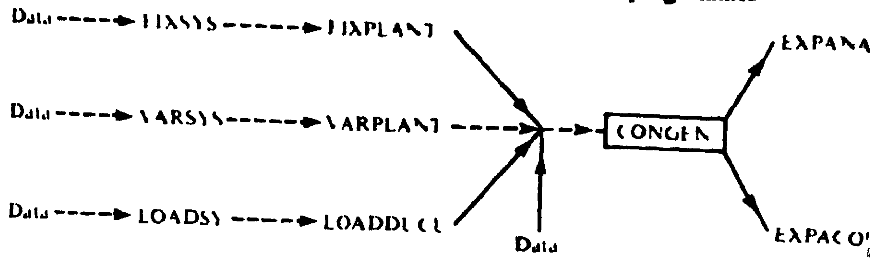
Step-by-step description of WASP programmes

Fixed system programme (FIXSYS)

The WASP package assumes that the study riod is divided into a number of stages, each ge being equal to a year The user has the cility of further sub-dividing a year into a mber of equal periods not exceeding twelve e selection of periods is of considerable portance in the study, as the period is the basic it of simulation The periods should be so osen as to adequately reflect characteristics ch as load variations, hydro-electric aracteristics (i e , seasonal factors) as well as heduled maintenance for generating units In fixed system programme, the generating units sting at the start of a study are described The ogramme permits a maximum of one hundred tions The plant type functions are as given in ble 13A-1

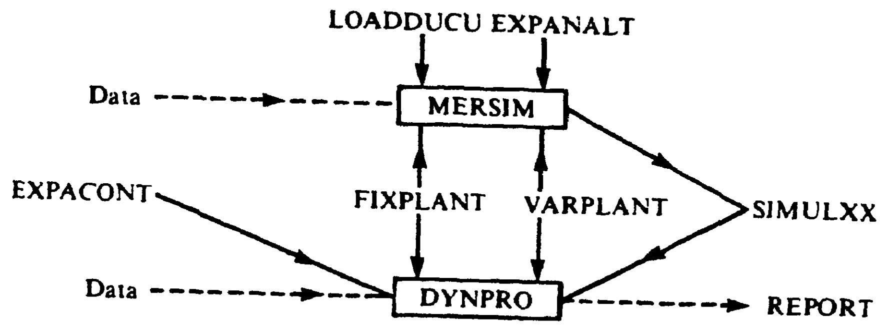
One of the four values for NTYPE can be used further sub-division of fossil fired stations, example, 1 = oil fired unit, 2 = gas turbine, d so on

Figure 13A-1 Linkages between WASP II programmes



Source (adapted from) Jenkins and Joy (1974)

Figure 13A-2 Linkages between WASP II programmes



Source (adapted from) Jenkins and Joy (1974)

LOADDUCL = Load description file
EXPANALT = Expansion alternative file
FIXPLANT = Fixed plant file
VARPLANT = Variable plant file
SIMULXXX consisting of
SIMULOLD = File containing operating cost of configurations of previous alterations and
SIMULNEW = File of current configurations

Table 13A-1. Plant type definitions in FIXSYS

NTYPE	Definition
0	Nuclear station
1, 2 3 or 4	Fossil-fired station
5	Hydro-electric system
6	Pumped storage system
-1	Emergency hydro-electric system

■ Thermal units

A thermal station is defined as an aggregate of identical generating units operating at the same fuel costs All existing thermal stations, i.e , nuclear and fossil fuel, must be included in the list Stations that are not part of the system at the beginning of the study, but which can be regarded as *formally scheduled* additions during the study period, must also be included.

The data required for definition of thermal stations are given in Table 13A-2

Table 13A-2: Data required for definition of thermal stations

Variable	Definition
NAME	Name of station
NSETS	Number of identical units in station at start of study
MWB	Base capacity for each unit (MW)
MWC	Total rated capacity of each unit (MW)
BHRI	Heat rate for base block of capacity (Btu KWhr)
CRMHRT	Average incremental heat rate for remaining capacity (MWC-MWB in Btu KWhr)
FCST	Domestic fuel cost (c MMBtu)
FCSTF	Foreign fuel cost (c MMBtu)
FOR	Forced outage rate (%)
MAINT	Average time the unit is required to be out of service for maintenance (days year)
MAINCL	Maintenance class capacity (MW)
OMA	Fixed non-fuel operating and maintenance cost ($ per KW per month)
OMB	Variable non-fuel operating and maintenance cost ($ MWhr)

In the probabilistic simulation approach, a thermal unit is considered to have two blocks of capacity—a base block and a peaking block. In Table 13A-2, MWB is the base capacity and the peaking capacity (also known as the load following block) would be MWC–MWB. As will be seen from the table, data on heat rates, fuel costs, forced outages, etc., are also required for the definition of thermal stations. Maintenance class capacity, i.e., MAINCL, is used in the maintenance scheduling algorithm which is part of the MERSIM programme.

■ **Hydro-electric system**

In the WASP package, the treatment of hydro-electric projects has not been done in detail. Individual hydro-electric projects are combined into an apparently single system. In WASP II, hydro-electric capacity is considered to be divided into two separate systems, namely, a normal hydro-electric system and an emergency hydro-electric system. The normal hydro-electric system includes capacity which is

Table 13A-3: Data required for definition of normal hydro-electric systems

Variable	Definition
NAME	Name of station
NSETS	Number of units (must = 1)
MWC	Nominal total capacity (MW)
MWB	Nominal 'run-of-the-river' capacity (MW)
ENERGY	Energy expected to be generated by the hydro-electric system each year (GWhr)
OMA, OMB	Same as for thermal units
	Period-dependent parameters
(HYDFAC)ᵢ	Multipliers of total capacity
(HYDFAB)ᵢ	Multipliers of 'run-of-the-river' capacity
(HENPRP)ᵢ	Distribution of annual energy (ratios)

continuously onstream (run-of-the- acity) as well as capacity used in p Hydro-electric generation is throughout the year in order to m costs of the thermal system. The en respect of the hydro-electric system is to be zero. The emergency hydro-ele describes that part of the hydro-ele that is used as reserve. This capacity into service only when other units are of service.

The data required for definition of hydro-electric system is given in Tab

The hydro-electric system will be d two separate capacities, run-of capacity (MWB) and peak-shaving (MWC–MWB), MWC being the total. As the run-of-the-river capacity represents the level at which the units m all times (i.e., base) the capacity (MWC is that available for peak-shaving d hydro-electric system includes period-de parameters. Capacity multipliers are de different periods, as both the capaci expected energy generation of the hydro system are period-dependent. In order t at the actual hydro-electric capacity period, the capacity figure has to be mult the relevant multiplier. Similarly, expected to be generated for each period be derived by multiplying the total yearly generation expected by the relevant multiplier.

Obviously, if the entire year is represe one single load duration curve (in other not sub-divided into shorter periods), ca multipliers and energy distribution ratios required. But this is normally not the ca most countries prefer to divide the year periods in order to better represent season other aspects of the electricity system.

■ **Emergency hydro-electric system**

Emergency hydro-electric projects are combined into a single composite system. W used, the emergency hydro-electric sy expends energy that would have been saved f future period. Therefore, the program provides a method for attributing a penalty the operation of this system. In order to calc the desired penalty for operating this unit, notional heat rate and fuel rate are assigned this system. These variables do not have physical meaning, and have been introduce the programme solely to enable a penalty t levied for the use of this system.

'umped storage system

pumped storage units (if there are more ıne) must be combined into a single ısite unit in the WASP package. Pumped . units at the start of the study, as well as to be added as formally committed lates during the study period, are included module The data required for definition pumped storage system are shown in Table .

Variations in WASP III

mentioned earlier, WASP III varies from ;P II in its treatment of hydro-electric ·ity WASP III has the advantage of more :d treatment of hydro-electric capacity, but :s *not* consider pumped storage WASP III, 'ore, is more useful for systems that are ɔminantly hydro-electric and was in fact oped for use in Argentina The difference in ment of pumped storage and hydro-electric in WASP III is explained later in ıection with the MERSIM module

Additions to or retirement from existing 'm

:heduled additions to, and retirement from, :xisting system are part of this module For mal units which are treated individually, it is :ssary to simply specify the station, number ıits added/deleted and the relevant year The ,ramme assumes that the changes occur at beginning of the year in question In the case ydro-electric, emergency hydro-electric or nped storage systems, changes are treated in a erent manner, namely, on composite basis as ed already Using the figures of added or :ted capacity change in energy specification ı period-dependent parameters, the capacity ighted average is calculated The idea is to ıve at a new composite unit, which would :ct the efficiencies and the period-by-period nation in hydro-electric capacity and energy the total system, which now incorporates the anges in the system during the study period

To sum up, the primary purpose of FIXSYS is assemble data concerning study of the existing wer system at the beginning of the study The gramme also has provision for formally mmitted additions or retirements during the dy period

Variable system programme (VARSYS)

While FIXSYS describes the initial conditions the system, VARSYS describes the units that are to be considered for expansion during the study period This programme can be dealt with briefly here as the data required are identical to that required to describe the fixed system A maximum of twenty candidate types will be described in this programme

Table 13A-4· Data required for definition of the pumped-storage system

Variable	Definition
NAME	Name of unit
NSETS	Number of units (must = 1)
MWB	Electrical load imposed by pumps (MW)
MWC	Generating capacity (MW)
ENERGY	Maximum feasible energy which could be generated in on period (GWhr)
OMA, OMB	Same as for thermal units
PEF	Efficiency of pumps (expressed as a fraction)
CEF	Generation efficiency (expressed as a fraction)

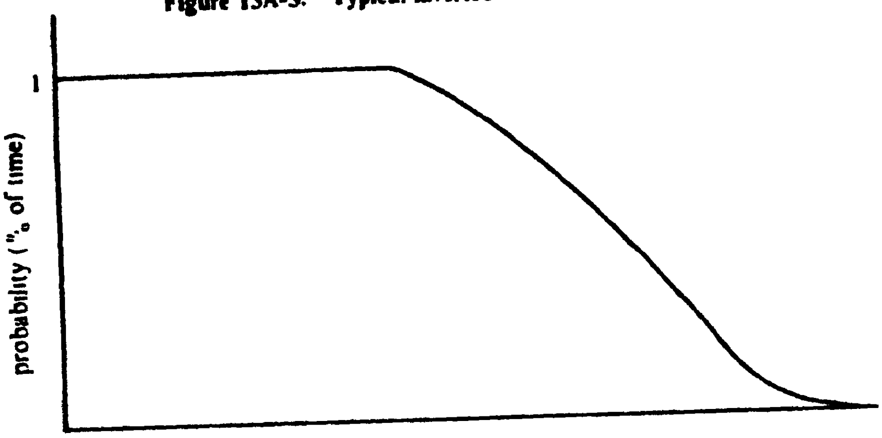
Hydro-electric and pumped storage candidates have to be merged with the existing system and simulated as a single composite entity A maximum of twenty hydro-electric projects can be included in the single hydro-electric candidate type, similarly, twenty pumped storage projects can be included in the single pumped storage type.

It is not possible to retire candidates defined in this programme This is not a serious limitation on the model, as most studies cover a shorter period (10 to 20 years) than the life-span of most generating units (25 to 30 years)

Load description programme (LOADSY)

This programme defines the forecast demand and energy requirements of the system during the study period As will be seen later in our discussion of probabilistic simulation in the MERSIM module, 'inverted' load duration curves are required for every period in the study For example, if the total study covers twenty years, and each year is divided into twelve periods, two hundred and forty such curves are to be generated The normal load duration curve is 'inverted' by showing the load (MW) on the horizontal axis and the time variables on the vertical axis Time, instead of being shown in 'hours', it is shown as fractions of the period for which system load equals or exceeds the associated power The horizontal axis can then be considered to represent the *probability* that a particular system load will be equalled or exceeded (Figure 13A-3 shows a typical inverted load duration curve)

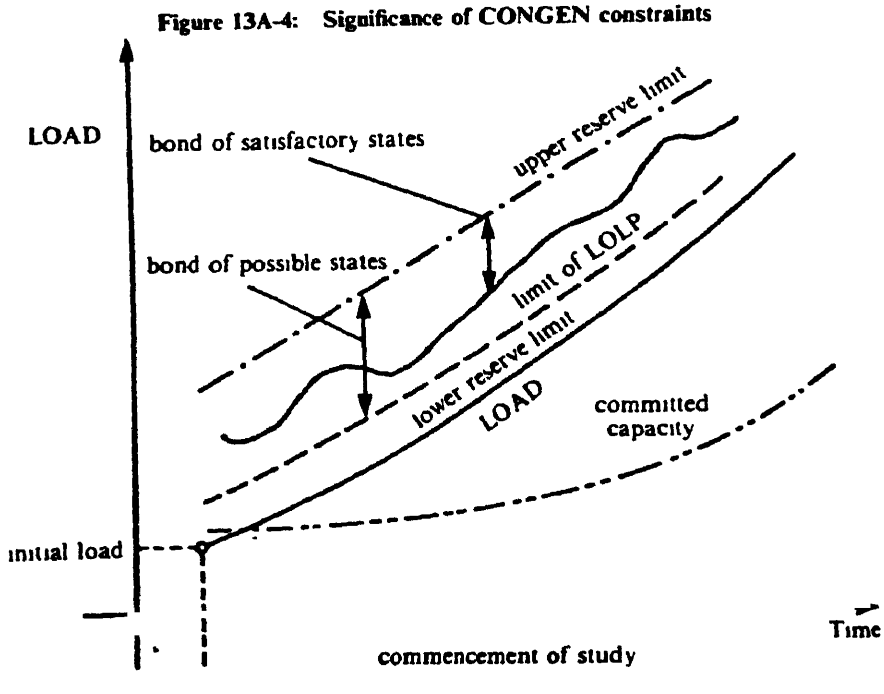
Figure 13A-3: Typical inverted load duration curve



The main function of LOADSY is to generate a *discrete* load duration curve for each period, the number of discrete points to be specified by the user, who does this by identifying the capacity to be associated with each discrete point (DM) This specification is to be based on a combination of judgement and experience A small value of DM will result in an almost continuous load duration curve but increase computation requirements Thus a trade-off has to be made between accuracy and computation requirements Jenkins and Joy (1974) suggest, as a guideline, that approximately 100 to 350 discrete points be used to represent the load curves over the study period, and then the corresponding value of DM be rounded off to the nearest 25 MW.

3 *The table of possible expansion states is not shown here but may be seen in Jenkins and Joy (1974) p 40*

Figure 13A-4: Significance of CONGEN constraints



LOADSY calculates not only lo
each period (and annual load fac
generates period-wise inverted l
curves for use in MERSIM's
simulation sub-programme, which
later.

Expansion configuratio generator programme (CONGEN)

CONGEN defines the possible
expanded power system for each
study Its primary purpose is to enal
planner to exercise his judgement
states generated and prevent the co
examining all the theoretical
configurations The CONGEN pro
this by enabling the planner to set
and maximum reserve requireme
constraints on the allowable numb
each expansion candidate each year
(called 'tunnel' constraints)

A simple example given by Jenk
(1974) considers an existing system
FIXSYS) B, with three expansion
under consideration, *viz*, 1,000 MW
500 MW coal fired (C), and 100 M
peaking units (P) In a twenty-year
are 74 possible expansion configu
capacities between B and B + 2,00
assumed that 100 MW are added
every year [3]

The two types of constraints
earlier may be considered against
example Firstly, if it is assumed that
minimum and maximum reserve
are between (B + 500) and (B + 1,5
number of acceptable states is reduc
36 In the same example, if the us
'tunnel' constraints, fixing a maxim
peaking units, two coal units, or a s
unit in the permissible expansion
then the number of allowable states
down further to 16 Figure 13A-4 ill
significance of constraints deal
CONGEN

CONGEN, thus, enables the
reduce computational requirements
optimisation calculations by elimin
states which the planner, on the basis
knowledge and experience, regards
uneconomic states. As will be seen
optimisation programme will inform
any of such restrictions acted as a co

solution If this happens, the restrictions can e-defined and a new optimisation worked . This procedure is continued until an optimal tion is found, free of user-imposed ictions

Merge and simulate programme (MERSIM)

Maintenance scheduling in MERSIM ule

While probabilistic simulation is the hub of MERSIM module, maintenance scheduling s to be carried out *before* the production-sting exercise Maintenance, too, is treated in a babilistic manner in this module, as intenance scheduling cannot be foreseen curately over a long period, as is usually the e The concept of 'maintenance space', which related to the minimum reserve (installed pacity minus system load) for each period is ed in this programme The expected number of ys each unit will be out of service during each riod is worked out by multiplying the intenance requirement of the unit and the bability of the unit being on maintenance ring the period The figures of maintenance are ed in the production-coasting exercise sequently

Probabilistic simulation in MERSIM odule

The concept of probabilistic simulation for culation of operating costs was first oduced in France in 1967 and applied in veral electric utilities in Europe and the United ates in the 1970s This technique calculates the *rating costs* of an electric utility over a period time by forecasting the *expected* power neration by every plant in the system

This probabilistic simulation sub-programme WASP calculates system reliability and erating costs, using probabilistic methods It quires information such as system load curve, ading order, fuel costs and energy supplied by dro units The probabilistic simulation proach is useful in dealing with, for example, rced (thermal unit) outages

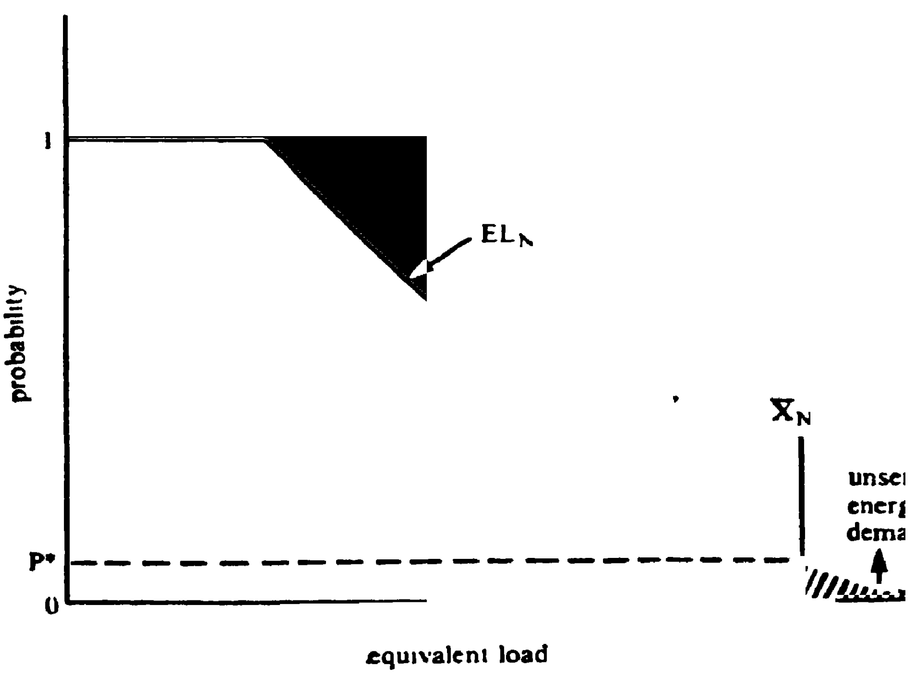
Using information on the system load curve, d the loading order, the expected generation of ery unit can be calculated when the capacity of e unit and the duration of the unit's nctioning is known However, in view of the npredictable) nature of forced outages for ermal plants, the element of probability is troduced in the programme. The probability of a particular unit being available is utilised to calculate the generation of the unit There is a separate probability figure attached to the availability of *each* unit in the system

The concept of 'load duration curve' has already been introduced and explained in the main chapter. For probabilistic simulation, the load duration curve is 'inverted', and the time variable is converted from 'time-hours' to 'percentage of total operating hours'. The time-variable is then considered to represent the probability that a particular system load will be equalled or exceeded

If all units were available all the time, in other words, if there were no forced outages, units can be loaded under the above load duration curve, and the generation of each unit can be easily calculated However, this is not so, and hence the concept of probability is introduced in respect of the working of each unit

Using the probability figure of each unit available, the programme generates 'equivalent inverted load duration curves', that is, curves which take into account the probabilistic nature of forced outages of each unit The equivalent curves can be generated for *each* unit, taking into account the forced outages of units above it in the loading order The final equivalent load duration curve takes into account the forced outages of all units in the system This is shown in Figure 13A-5

Figure 13A-5 Equivalent inverted load duration curve for entire system and uns demand



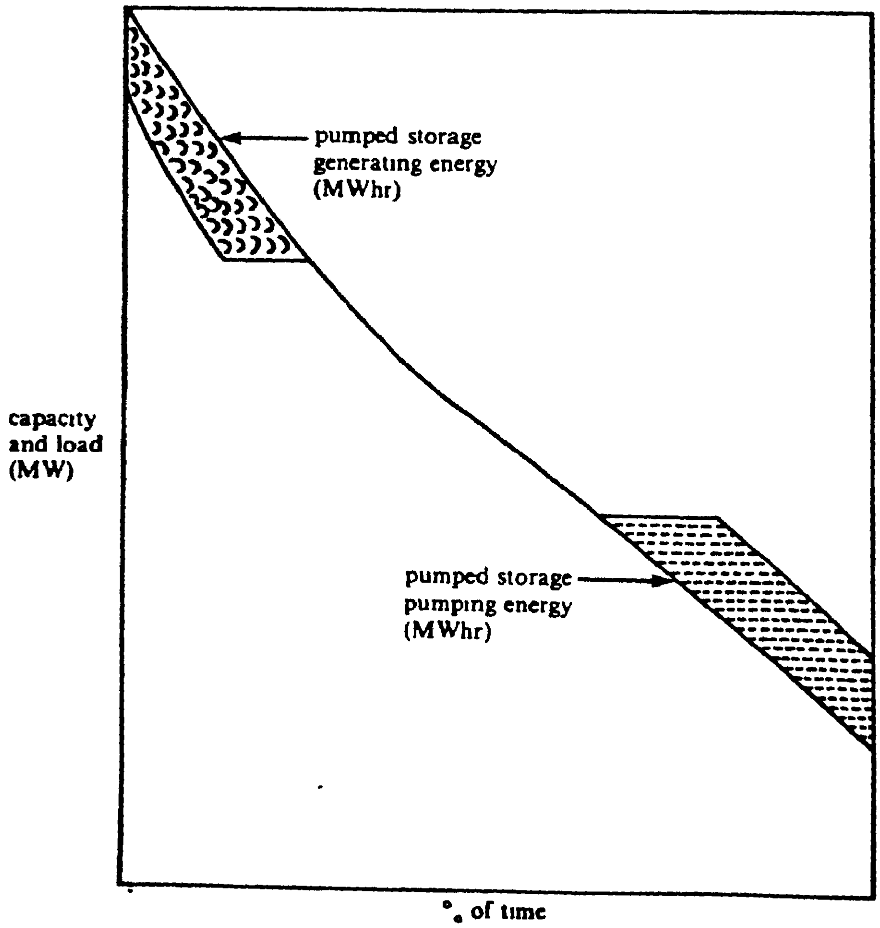
In the above diagram, EL_N is the equivalent inverted load duration curve for the entire system, taking into account the forced outages of all units X is the system capacity and unserved energy is the area to the right of X. Since the system will not be able to supply loads greater than the system capacity, P^* indicates the loss-of-load probability of the generating system

Two-piece representation of generating units In the WASP package, each generating unit can be divided into two capacity blocks, a base load block and a peak load block This helps in placing the blocks in non-adjacent positions in the loading order, that is, the base blocks are first loaded under the load duration curve and the peak blocks loaded later, depending on comparative costs, peaking requirements, etc.

Simulation of pumped storage and hydro-electric units The WASP II and WASP III packages differ with one another in their treatment of these units Hydro-electric units are simulated to a limited extent in WASP II. It has already been explained, while describing the

4 *It should be noted that the load duration curve shown is not the inverted curve*

Figure 13A-6: Simplified representation of pumped storage operations[4]



FIXSYS module, how hydro-electri... represented in a composite uni... probabilistic simulation sub-prog... total capacity of the apparently... hydro-electric unit is divided into two... base (run-of-the-river) block, and... block The base block is placed i... position in the loading order, fo... thermal units The peak-shaving hydro... is *not* included in probabilistic s... though it is used to meet the peak de... system In WASP III, as we shall see t... hydro-electric capacity is treated in... detailed fashion.

Pumped storage. As explained... discussion of the FIXSYS module,... storage units are also lumped together... composite unit A pumped storage u... water from its upper reservoir during p... to generate energy During off-peak h... night hours), the baseload generating... used to pump water back to the upper r... This is illustrated in Figure 13A-6

■ Treatment of hydro-electric, pumped... projects in WASP III

In the WASP III version, hydro... projects are treated in somewhat great... Such detailed treatment of hydro... capacity has corresponding impacts ... probabilistic simulation Hydro-pla... divided into two types: Type A, coveri... term storage, and Type B, covering long... seasonal) storage Short-term storag... include run-of-river, daily regulating and... regulating reservoirs, whereas long-term... represents seasonal regulating reservoi... type of hydro is also divided into base a... blocks

In the simulation process, WASP II d... consider the effects of random outa... thermal plants on the loading of hydro p... the load duration curve. In WASP III,... plants (including those for peaking capac... loaded into the equivalent load duration... Hence, the simulation of hydro plants is... realistic as well as more complete than WA... In fact, in WASP III, if peaking hydro en... more than the quantity required pur... peaking purposes, some thermal plants c... 'offloaded' (i.e., stop their generation) ... simulation process.

■ Consideration of spinning reser... MERSIM

The MERSIM programme has a sub-ro... called MILORD (MERSIM Integrated Lo...

r Generator), which defines the loading of base and peak blocks of various types of s[5] The following criteria are used: (a) basic ng order (the economic loading order based st information); (b) spinning reserve of each al plant (% of MW capacity), and (c) red minimum spinning reserve of the system RES) Loading can be done unit by unit or by plant

NRES can be either defined as a constant (> 5.0) or as a function of peak demand d-wise) and the largest single capacity k in the power system

efore commencing the exercise, information ase and peak block capacities is collected thermal plants (each with its individual ing reserve) contribute to the system ing reserve (CUMRES) when loaded

t the beginning of the exercise, the spinning ve of the hydro system (hydro plus gency hydro, in WASP II) is assigned to IRES Also, the base hydro capacity is first Base blocks of thermal plants are essively loaded in the known sequence of (economic) loading order, as long as IRES > SPNRES When the addition of a cular baseblock would make CUMRES < RES, then the lowest peak block is dered for loading, when a peak block is d, the contribution of spinning reserve of associated baseblock is deducted from IRES If the addition of a particular peak would make CUMRES < SPNRES, then eak block is not loaded, and the next (not aded) baseblock is loaded In this loading ss, the last to be loaded would be the peak block, and the emergency hydro block

athematical treatment of ERSIM

ce the various possible expansion states ited by the CONGEN programme are ble, the MERSIM module calculates the ing cost of each such expansion state

RSIM works out an estimated nance schedule before performing actual ction-costing It is known that the nance of units has a significant effect on tem operating costs and unit availability period In general, the maintenance of an be scheduled during times when the capacity reserves are greatest. For long-udies, it is difficult to foresee the realistic maintenance schedule of units; hence, WASP uses the concept of probabilistic maintenance scheduling The maintenance scheduling algorithm used in WASP is briefly summarised here The 'minimum reserve' for each period is equal to the difference of installed capacity and system load during the period Maintenance space is defined as the minimum reserve minus any previously scheduled maintenance for that period The value of each 'maintenance class' approximates the capacity of the units included in that class The total maintenance requirement of a maintenance class (MWDAYS) is derived from the following

$$MWDAYS = \sum_i (MWC)_i \times (NOSETS)_i \times (MAINT)_i \qquad \text{Equation 1}$$

where $(MWC)_i$ is actual capacity of unit (MW), $(MAINT)_i$ is maintenance requirement for each unit (days/year), $(NOSETS)_i$ is number of identical units at station and i is index of stations in a maintenance class

A maintenance block represents the amount of maintenance that could be performed by the removal of a specific capacity for the entire period

$$MAINBK = (MAINCL) \times T_p \qquad \text{Equation 2}$$

where $MAINBK$ is maintenance space available in a maintenance block (MW days), $MAINCL$ is capacity of a maintenance class (MW) and T_p is length of period (days)

The number of blocks required for each maintenance class is calculated as

$$NO = \frac{MWDAYS}{MAINBK}$$

and the blocks are sequentially assigned to the period that has the largest maintenance space An approximation must be made for a fractional block as it is not possible to sub-divide a period in the probabilistic simulation Therefore, for any remaining maintenance, the class size must be adjusted to allow the maintenance to extend over the entire period The capacity of a fractional block is calculated as

$$MCLL = \frac{REMAIN}{T_p} \qquad \text{Equation 3}$$

5 *A worked out example of 'a loading order generated by MILORD is contained in 'MILORD and Dispatch of Hydro, etc', by Peter Heinrich, IAEA, 1979 The discussion here closely follows Heinrich's treatment*

where *MCLL* is estimated capacity for fractional maintenance block (MW) and *REMAIN* is maintenance requirement for fractional maintenance block (MW days)

The expected number of days each unit will be out of service during each period (D), is worked out by multiplying the maintenance requirement of the unit and the probability of the unit being on maintenance during the period The expected outage rate of maintenance is defined as the ratio of number of maintenance days per period to number of days in a period The figures of maintenance and forced outage are utilised by MERSIM to work out system operating costs

The *probabilistic simulation sub-programme* (of MERSIM) is basic to the understanding of WASP. This programme calculates the system reliability and operating costs, using probabilistic methods. It requires information such as system load curve, loading order, fuel costs and energy supplied by hydro units The probabilistic approach is useful in dealing with, for example, forced (thermal unit) outages

The expected generation of the ith unit, E , is given by integrating the inverted load duration curve between the proper limits (Figure 13A-7)

$$E_i = T \int_{a_i}^{b_i} L(x)dx \qquad \text{Equation 4}$$

where T is time period of load duration curve, $L(x)$ is inverted load duration curve, a_i is system capacity for units 1, 2 . $(i-1)$, b_i is system capacity for units 1, 2 . .(i)

If all units were available *all* the time, the above equation would accurately estimate the energy generation However, in order to include the element of (unpredictable) forced outages, p (the probability that unit 1 is available to produce full power), and q (the probability that it is unavailable) have to be introduced Obviously, $p + q = 1\ 0$ where q is called the forced outage rate Figure 13A-8 illustrates the change

It will be clear from the above figures (inverted load duration curve is the same) that the expected generation of the units varies significantly with the outage of unit 1.

The expected generation of unit 1 is given by

$$E_1 = P_1 T \int_{a_1}^{b_1} L(x)dx \qquad \text{Equation 5}$$

Unit 2's generation, however, depends on unit 1's availability. Unit 2 will be loaded (probability P) according to Figure 13A-7 or Figure 13A-8, depending on whether unit 1 is available or not

Therefore,

$$E_2 = P_2 T \left[P_1 \int_{a_2}^{b_2} L(x)dx + q_1 \int_{\alpha_2}^{\beta_2} L(x)dx \right] \qquad \text{Equation 6}$$

where a_2 and b_2 are integration limits based on Figure 13A-7 and a_2 and β_2 are integration limits based on Figure 13A-8

An equivalent representation of an outage of unit 1 (which is followed in the WASP programme) is to leave unit 1 in its original

Figure 13A-7: Unit loading (all units 100 % available)

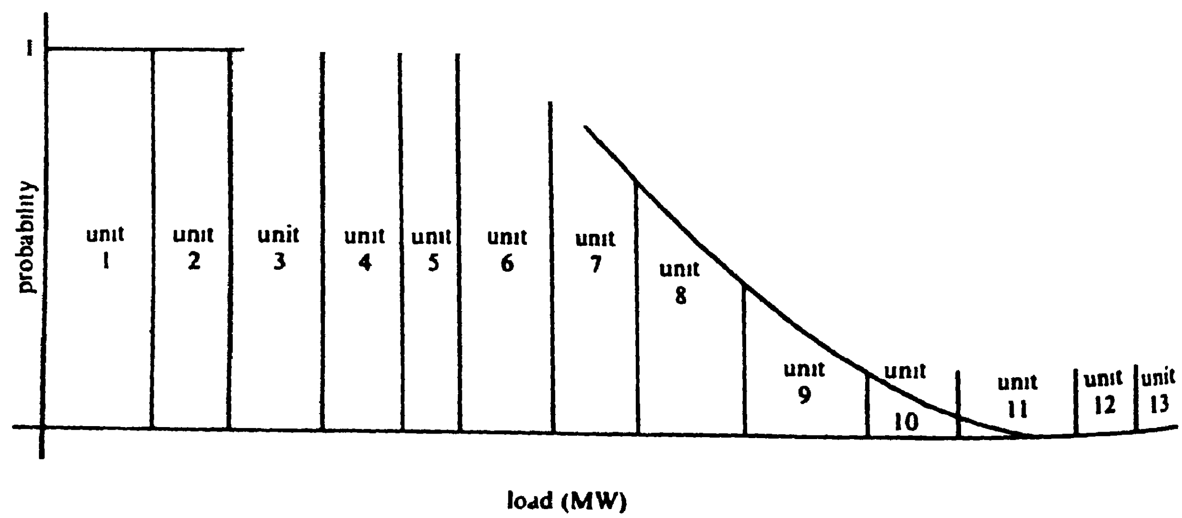
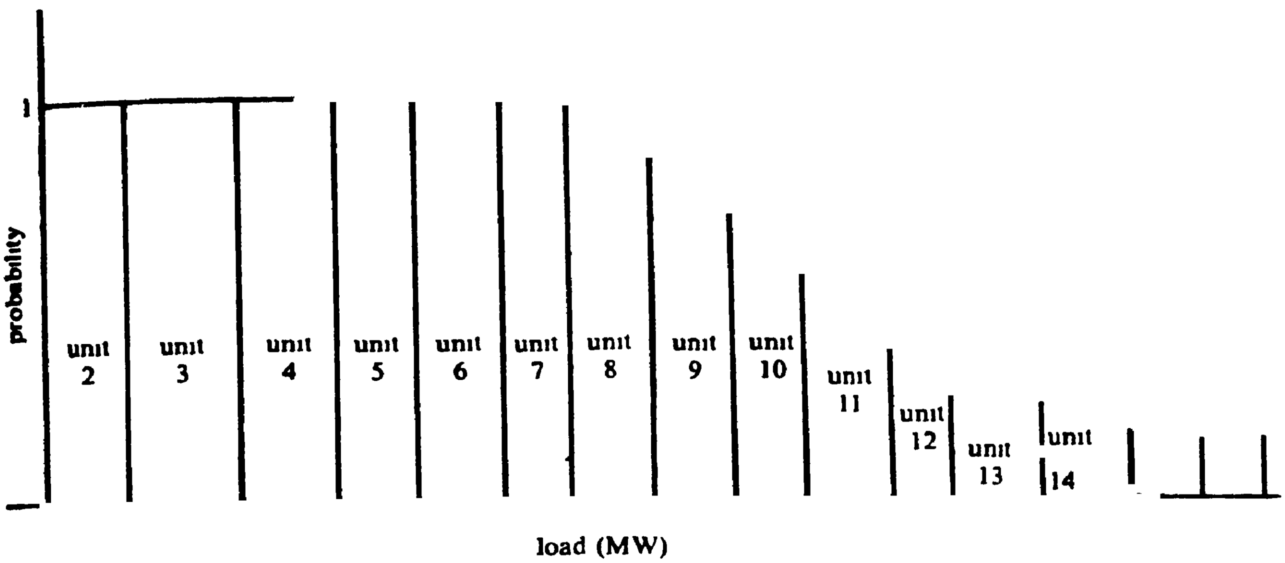


Figure 13A-8. Unit loading (unit 1 not available)



position and shift the inverted load duration curve to the right by the capacity of unit 1, as shown in Figure 13A-9

Obviously, $L'(x) = L(x - MW_1)$ Equation 7

Therefore,

$$\int_{a_2}^{b_2} L'(x)dx = \int_{a_2}^{b_2} L(x - MW_1)dx$$

Equation 8

The probability of unit 2 being loaded by curve L is P_1, and by curve L', is q

i e $\int_{a_2}^{b_2} L(x)dx$ can be substituted by

$$\int_{a_2}^{b_2} L'(x)dx \text{ and hence } \int_{a_2}^{b_2} L(x - MW_1)dx$$

Equation 9

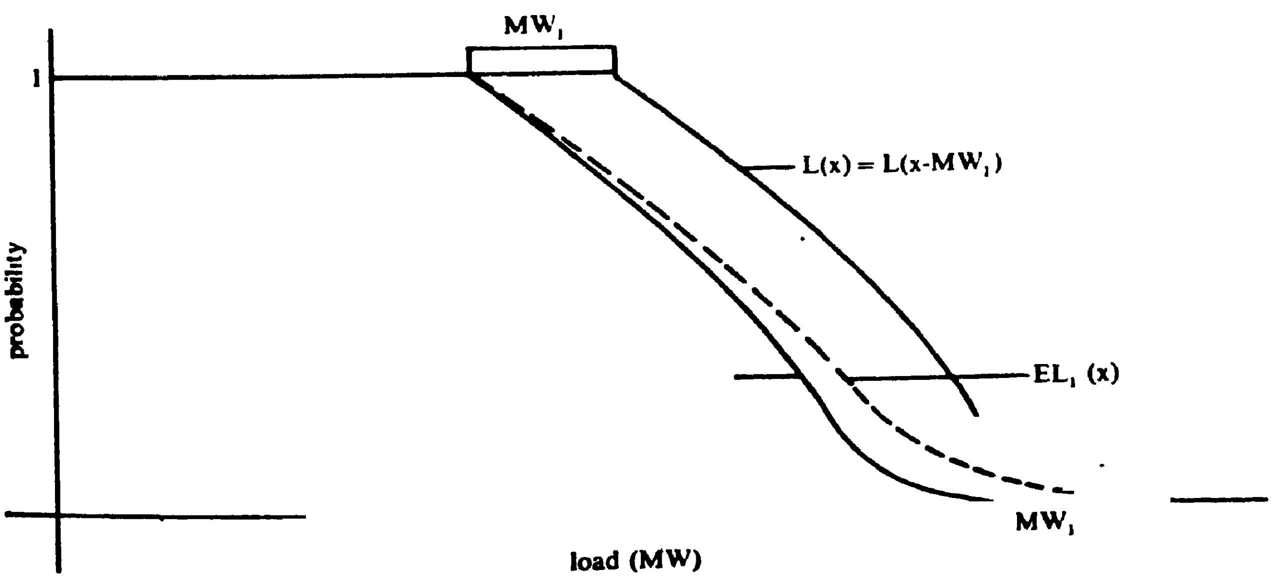
in equation 6 above Rewriting equation 6,

$$E_2 = P_2 T \int_{a_2}^{b_2} \Big[P_1 L(x) + q_1 L(x - MW_1) \Big] dx$$

Equation 10

Figure 13A-9 shows the concept of *equivalent load* graphically The equivalent load curve takes into account the outages of all the units before the unit under consideration for loading, e g equivalent load of unit 2 will consider outages of unit 1, and the *additional* operation required of unit 2

Figure 13A-9: Equivalent load



EL = equivalent load curve of unit 1, is obviously the *same* as the inverted load duration curve.

EL_1 = e l c of unit 2, would be evaluated by multiplying the additional load by the probability of having to serve it,

i e. $EL_1 = L(x) + q_1[L(x - MW_1) - L(x)]$

Equation 11

i e. $EL_1 = P_1 L(x) + q_1 L(x - MW_1)$
(as $P_1 + q_1 = 1$ by definition)

Equation 12

Substituting equation 12 into equation 10 yields,

$$E_2 = P_2 T \int_{e_2}^{\phi_2} EL_1(x)dx \qquad \text{Equation 13}$$

Expected generation for the nth unit will be,

$$E_n = P_n T \int_{e_n}^{\phi_n} EL_{n-1}(x)dx \qquad \text{Equation 14}$$

The final equivalent load duration curve includes the forced outages of *all* units, and p* in this final equation will obviously be the loss-of-load probability of the entire generating system

Simulation of hydro-electric projects In this, there is a significant difference between the WASP II and WASP III packages, as has already been briefly mentioned earlier. While WASP III does not handle pumped storage units, it deals with hydro-electric projects more elaborately in the probabilistic simulation programme The simulation of hydro plants in WASP II has already been explained (the base blocks are simulated along with the base thermal plants and the peak blocks are used for 'peak shaving') In WASP III, the loading of hydro plants takes into account the effect of random outage of thermal plants in the simulation process Some of these features are dealt with in the following paragraphs

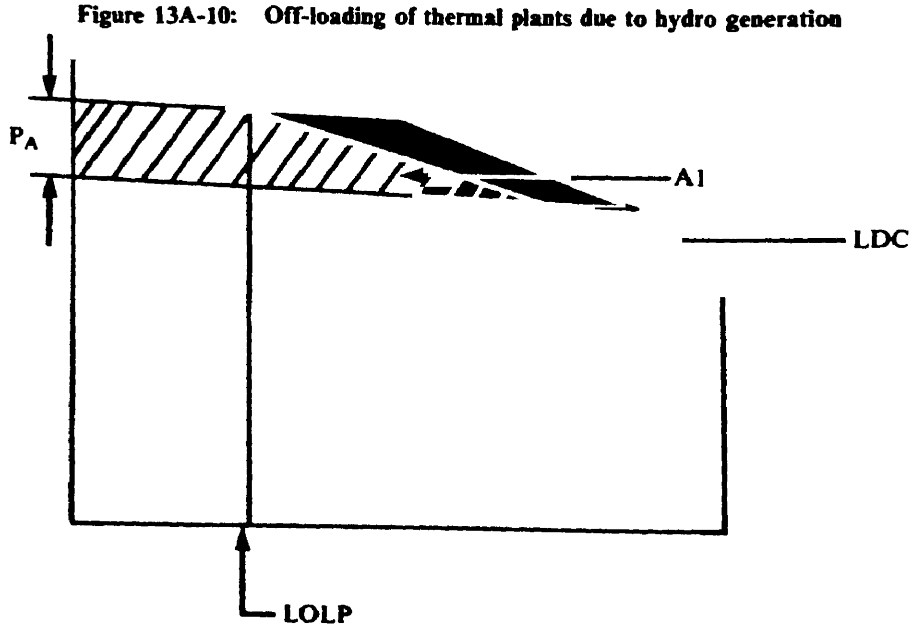
Off-loading of thermal plants in MERSIM module owing to hydro generation: A case may arise in the simulation process whereby the hydro energy available for peaking is greater than the area *A* , intercepted on the load duration curve by the corresponding peaking capacity block *(P)* as shown in Figure 13A-10.

To utilise this surplus energy, the capacity block *P* is moved downward and the thermal plant immediately next to the peaking hydro block, is 'off-loaded' This off-loading process continues until all the surplus hydro energy is used up.

LOLP in the MERSIM module In WASP III, too, the LOLP calculation takes into account the energy of hydro-electric plants Figure 13A-11 illustrates the approach adopted.

MWB_H and MWP_H are the composite hydrobase capacity and peaking capability, respectively $ELDC_N$ is the equivalent load curve

Figure 13A-10: Off-loading of thermal plants due to hydro generation



f the entire system A_1 is the area under the ırve intercepted by hydropeaking capacity MWP_H The capacity of thermal plants is shown ter derating for maintenance Let the energy ·ilable for peaking be EH

The possibilities are

(a) $EH_p > A_1$

(b) $EH_p = A_1$

(c) $EH_p < A_1$

For (a) and (b), the LOLP is obviously as ıdicated in Figure 13A-7

In the case of (c), the hydro-plant will supply ll available energy at reduced output as lustrated in Figures 13A-12 and 13A-13 where NS = energy not served

In Figure 13A-13, the area under the curve H_p is equal to the rectangular EH_p in Figure 3A-12 where ENS is in two parts (C_1, C_2) This as been brought to the right as in the triangle hown in Figure 13A-13. The change has been rought about by appropriate operations of the ydro peaking capacity The LOLP in this case is ıdicated in Figure 13A-13

ENS is calculated by the MERSIM module as he generation of a fictitious unit (infinite apacity, i e, $MW = \infty$, and forced outage ate = 0)

$$ENS = \left| \int_{ICP}^{\infty} ELDC_N(x)dx \right| \qquad \text{Equation 15}$$

where ICP is system capacity, $ELDC_N$ is equivalent load duration curve considering outage of all plants

■ Hydro-energy spillage in MERSIM module (WASP III)

Figures 13A-14 and 13A-15 illustrate the reporting of hydro-spillage (SP_H) in the MERSIM module In the former, this happens when the top portion of the peaking hydro blocks (P_A) reaches the minimum load before all hydro-energy is utilised In the latter, the base capacity of the hydro plant is greater than the minimum load of the system

■ Plant production-costing in MERSIM module

After evaluating the expected generation of each thermal plant, the local fuel expenditure of

Figure 13A-11: LOLP in WASP III

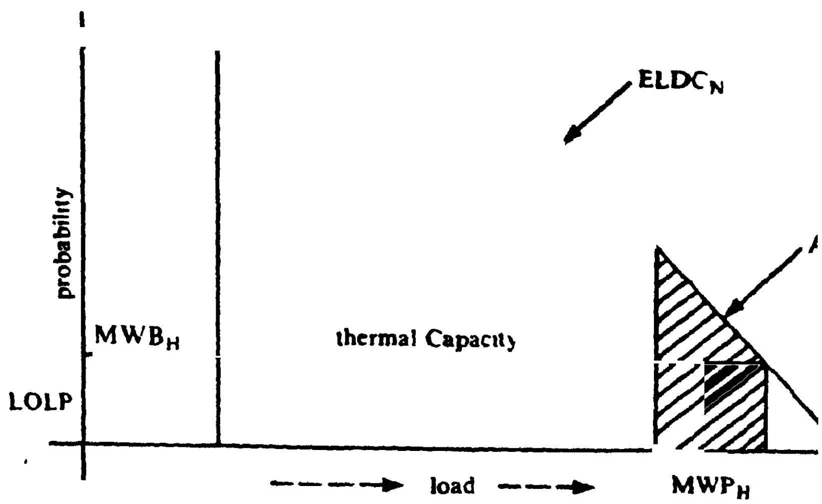


Figure 13A-12· Calculation of energy not served (i)

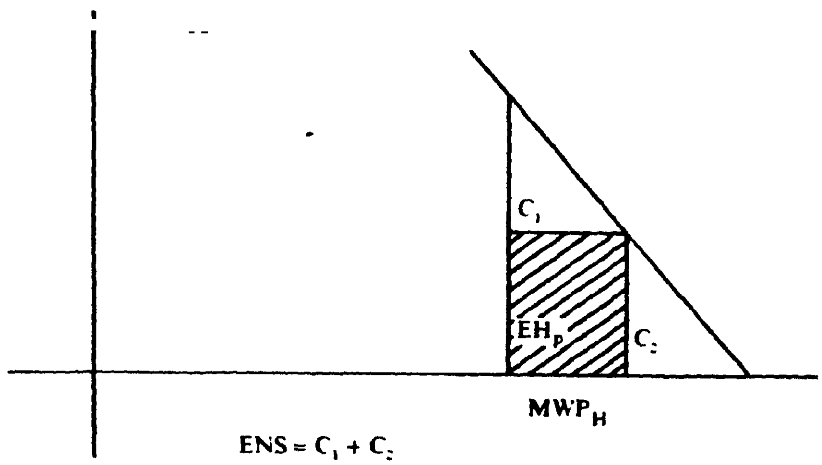
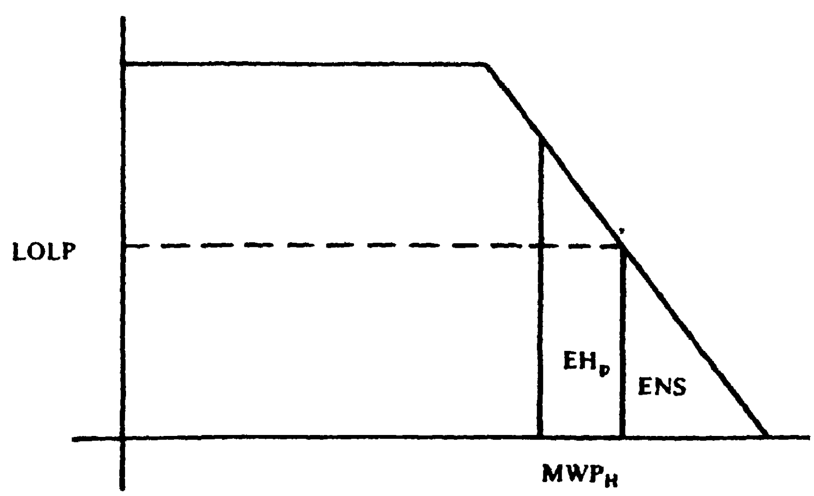


Figure 13A-13. Calculation of energy not served (ii)



each thermal plant considered by the configuration is calculated from

$$FCL_i = [(ENGB_i \times BHRT) + (ENGP_i \times CRMHRT)]FCST \times 10^{-2}$$

Equation 16

where FCL_i is local fuel expenditure of the plant in period i, $ENGB_i$ is expected generation of base portion of the plant in period i, $BHRT$ is heat rate of the base portion of the plant in period i, $ENGP_i$ is expected generation of remaining capacity of the plant in period i, $CRMHRT$ is incremental heat rate for remaining unit capacity (k cal/kwh) and $FCST$ is local fuel cost of the plant (cents/10 K/Cal).

6 *The variable operating and maintenance cost of the plant has not been considered in these studies*

The non-fuel (operation and maintenance) expenditure of each thermal plant is calculated from·

Figure 13A-14: Reporting of hydro-energy spillage (i)

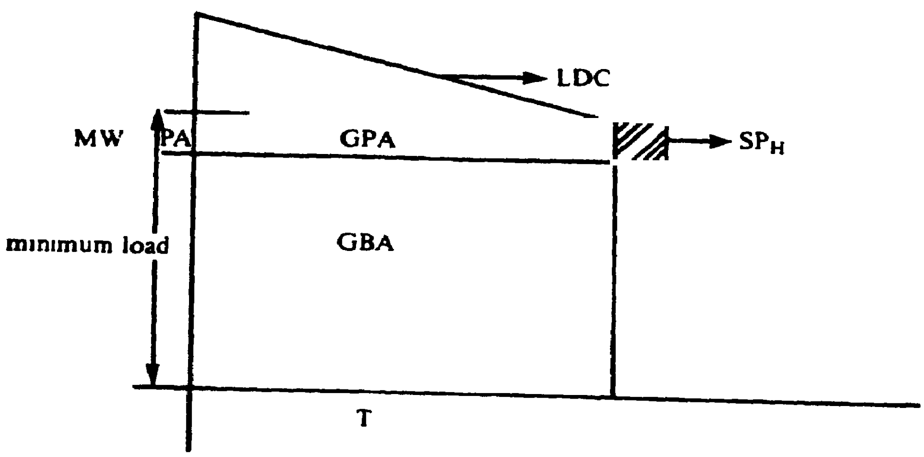
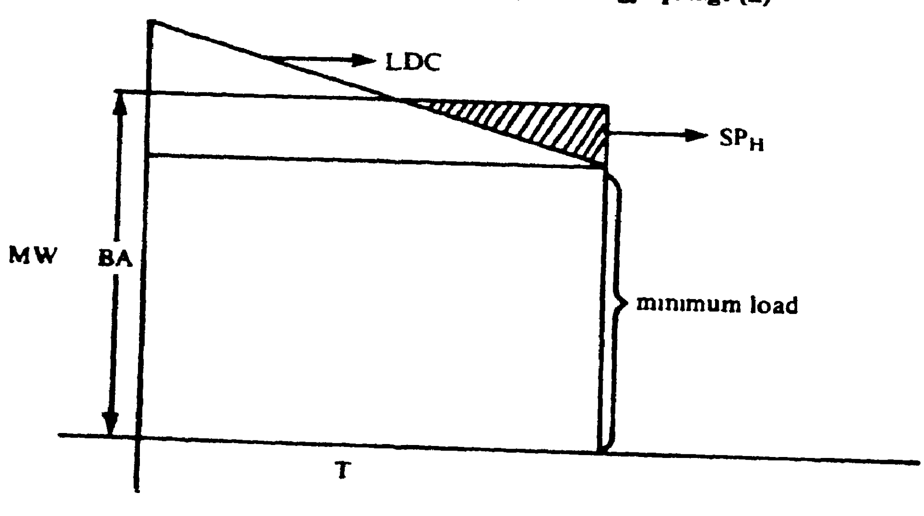


Figure 13A-15 Reporting of hydro-energy spillage (ii)



$$OAM_i = \left[OMA \times \frac{12}{NPER} \times M \right.$$

$$\left. NSETS \right] \times 10^3$$

where OAM_i is non-fuel expenditu in the period i, OMA is fixed o maintenance cost[6] of the plant ($ $NPER$ is number of periods in the maximum capacity of each unit (MW) and $NSETS$ is number of ide the plant

The operating and maintenance projects is worked out as

$$OMH = \left[OMA \times \frac{12}{NPER} \times MW \right.$$

where OMH is operation and main of hydro projects, OMA is op maintenance cost $ /kw-month number of periods per year and MW capacity of hydro-electric projects

The cost of operation is reported type for each period of the study co to all the configurations being simu module

Optimisation programme (DYNPRO)

The DYNPRO module is the one optimisation exercise is conducted cost expansion plan selected from available from the CONGEN m programme minimises the presen value of the capital and operating expansion programme during the 'Dynamic programming' is used to optimisation

Dynamic programming is genera decision-making problems that invo which take place in several stages processes) in such a way that at ea process is dependent on the stra Thus, dynamic programming is co the theory of multi-stage decision pr a process in which a sequence of decisions have to be made The so dynamic programming problem sequentially, starting from the initia next till the final stage is reached.

It is important to note that the concept of dynamic programming is largely based on the Bellman's principle of optimality

'An optimal policy has the property that, whatever the initial state and initial decision are, the remaining decisions must constitute an optimal policy with regard to the state resulting from the first decision'.

Characteristics of dynamic programming

The basic features which characterise dynamic programming are

(i) it can be sub-divided into stages, with a policy decision at each of the stages,

(ii) every stage consists of a number of states, which are the different possible conditions in which the system may find itself at that stage of the problem,

(iii) the decision at each stage converts the current state into the state associated with the next stage, and

(iv) once the current state is known, an optimal policy for the remaining stages is independent of the policy of the previous one

Mathematical treatment of DYNPRO

As explained, the objective of this programme is to find the least-cost expansion plan during the planning period, the economic criterion of judgement being the present worth discounted value of all capital investment costs (of the variable system plants) plus all operating costs, less a salvage value credit at the horizon for the remaining economic life of the plants In mathematical terms,

$$\text{minimize } B_j = \sum_{t=1}^{T} \sum_{j=1}^{J} I_{j,t} - S_{j,t} - F_{j,t} + \bar{M}_{j,t} + \bar{Q}_{j,t}$$

Equation 19

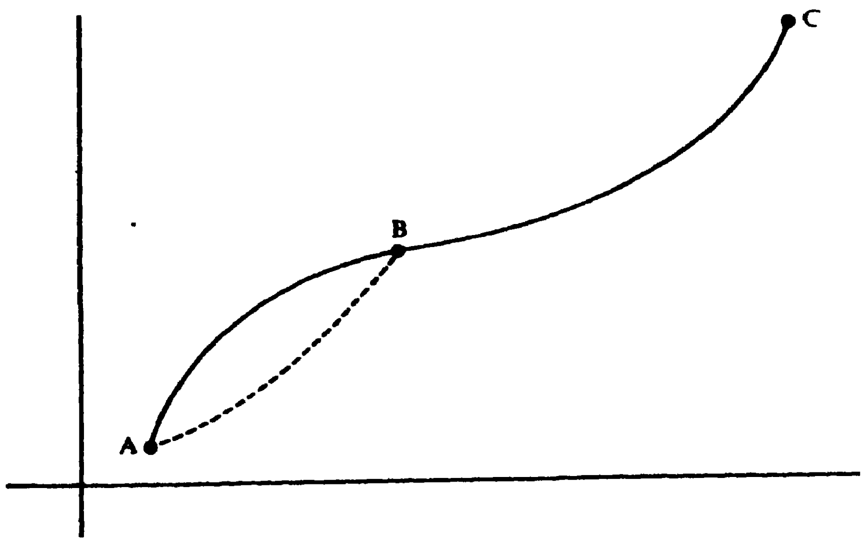
where I is capital investment cost of plants in VARSYS, S is salvage value of VARSYS plants, F is fuel costs, M is non-fuel operation and maintenance costs, Q is cost of energy not served, B is objective function of expansion plan j, t is time (year 1 .. .. T), T is length of study period in years and the bar over symbols means 'discounted values to a reference date at a given discount rate'

The DYNPRO module considers all the configurations in the latest CONGEN data file and the corresponding operating costs/reliability information in the MERSIM data file, together with information on capital costs, other economic parameters and the acceptable reliability criterion It rejects configurations not meeting the reliability criterion (i e., largest acceptable LOLP value) and chooses from the remaining configurations the least-cost expansion schedule of new unit additions during the study period The optimal solution thus obtained is only the lowest cost solution within the constraints imposed in CONGEN. DYNPRO reports if the constraints had actually constrained the solution The CONGEN, MERSIM and DYNPRO modules are executed alternatively, changing the input data in the direction indicated by the solution constraints messages given by the latest DYNPRO run This process continues until an unconstrained optimal solution is reported.

Bellman's principle of optimality

Dynamic programming is based on Bellman's principle of optimality Figure 13A-16 illustrates the principle To begin with, B is considered as an intermediate point on the optimal trajectory The portion of the solid line from A to B must also be the optimal path between these points Otherwise, there should be another path between the two points which results in a lower cost than the solid line The dotted line represents such a path The existence of this dotted line will violate the original assumption, since a lower-cost path from A to C could be obtained by moving along the dotted line A to B and then the solid line from B to C Therefore, if the optimal path A to

Figure 13A-16· Illustration of principle of optimality



C is to be found, the only factor to be determined is the optimal path from point A to each intermediate point on the optimal trajectory between points A and C.

To find the optimal path from A to C, the principle of optimality can be applied by finding the optimal trajectory to every state in each stage The state in the previous stage that lies on the optimal trajectory to the state under consideration is saved To find the optimum path to any state in stage j, the optimum paths to all states in stage j-1, with their associated values of the objective function and the cost of proceeding from each of these states to the state under consideration in stage j, should be known By recursive application of this principle, the optimal path to any state in any stage can be determined The global optimum over the study period is associated with that state in the final stage which has the lowest value of the final objective function, and the optimal trajectory is determined by tracing backward from this to the initial condition The calculational technique can be further demonstrated by a simple example consisting of three stages as shown in Figure 13A-17. No choices are involved in locating optimum paths from the initial state to states 1 and 2 in stage 1 The associated cost functions are I(1) and I(2), respectively In progressing from stage 1 to stage 2 four possible paths exist, two to state 3, and two to state 4 Considering state 3, it is seen that one path to this state originates from state 1 and the other from state 2. The values of the objective functions for the paths arriving at state 3 are then

$$L_1 = C(3-1) + I(1) \qquad \text{Equation 20}$$

$$L_2 = C(3-2) + I(2) \qquad \text{Equation 21}$$

where *C(3-1)* is cost of progressing from state 1 to state 3 and *C(3-2)* is cost of progressing from state 2 to state 3.

L_1 and L_2 are compared, and the path resulting in the lower value is retained as the optimal path to state 3. If it is assumed that the path from state 1 to state 3 resulted in the lower value of the objective function, then the minimum cost function for state 3 is

$$I(3) = L_1 \qquad \text{Equation 22}$$

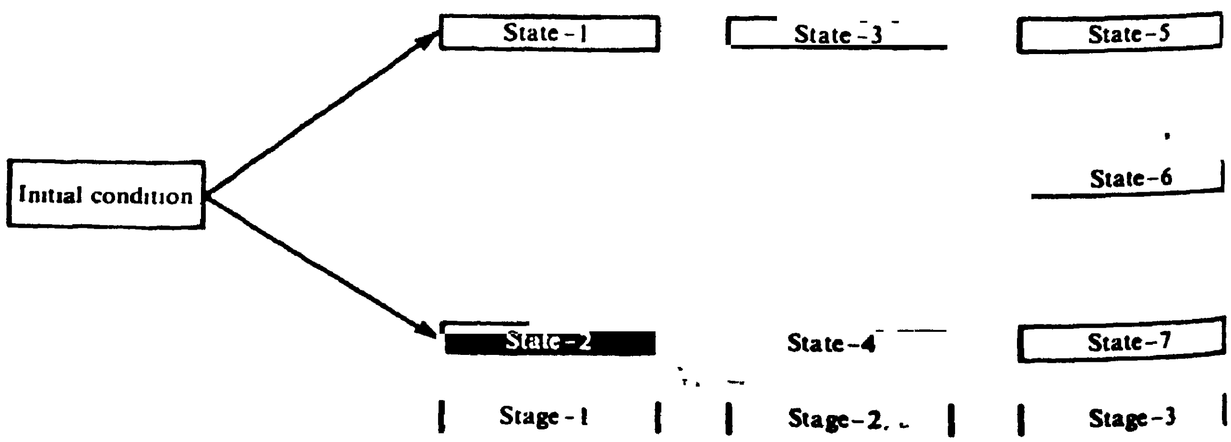
The path from state 2 to state 3 is discarded as being uneconomical and is not included in any further consideration involving state 3. Figure 13A-18 illustrates the two possible paths for arriving at state 3, with the optimal and non-optimal decisions being shown as a solid line and a dotted line respectively The same analysis is repeated for state 4, and again only the optimal decision is retained. In the third and final stage, too, the alternative paths lead from states 3 or 4 to states 5, 6 or 7 The same logic is applied to this set of decisions.

Figure 13A-18 also shows the optimal paths to each of the states in the final stage At this point, the optimal end state and the optimal trajectory can be determined by selecting the final objective function as

$$I = [\min I(5), I(6), I(7)] \qquad \text{Equation 23}$$

It may be assumed here that state 6 results in the minimum value of the total objective function The optimal path from state 6 is traced backward to the initial condition showing that states 1, 4 and 6 formed the optimal expansion policy It may well be that no decision is made as

Figure 13A-17: Sample state space for three-stage dynamic programming



to which state forms part of the optimal policy until all the states in every stage have been considered *This dynamic programming principle is applied in the WASP programme, where the initial state is defined in FIXSYS.* The states to be considered and any imposed limitations on the decisions are defined in CONGEN. The operating costs associated with any state are calculated in MERSIM and the optimal solution is determined by using the above principle

4 Application of WASP

This section briefly illustrates the application of WASP to two real-life electricity systems India and the Republic of Korea have been chosen, largely for reasons of ready information availability

for including bulk transmission directly, a two-step approach was adopted.

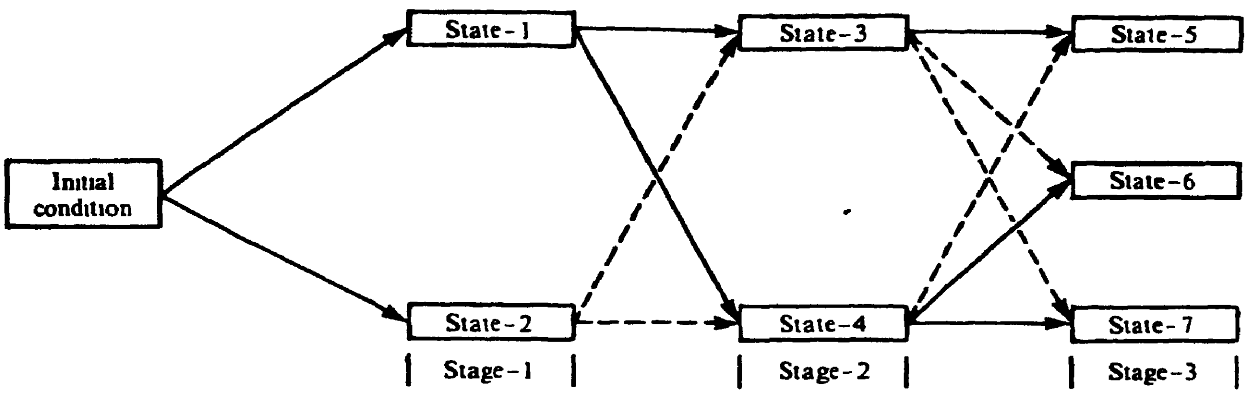
(i) firstly, alternative expansion patterns were identified and each pattern was optimised (using the WASP programmes) corresponding to the assumed criteria; and

(ii) secondly, for each alternative optimised pattern, the required bulk transmission facilities were determined

The results from these two steps were synthesised to develop an optimal generation-cum-transmission investment plan for the study period

The alternative criteria considered for

Figure 13A-18· Sample dynamic programme problem



The Indian case

The Indian electricity system has been divided by planners into five regions, recognising the inadequacies of administrative units such as states as planning units specifically in the context of uneven distribution of physical energy resources (mainly hydro sources and coal) and the advantages of integrating power systems of contiguous states These regions have been used as planning units for power system development In the 'national power plan' prepared by the Central Electricity Authority (CEA), it has been assumed that each region will be self-sufficient in power and there will be no exchange of power between regions

The basic objective of the long-term plan prepared by CEA in 1983 has been to determine generating capacity additions by types (hydro, thermal and nuclear), unit sizes (primarily nuclear and thermal) and their installation timings during the study period up to 1995. As the WASP computer code does not have facilities

developing the generation plans were broadly as follows

(i) Two alternative assumptions were made regarding the progress of hydro development the 'high hydro' option wherein all hydro projects identified as feasible (by CEA) during the study period would be taken up in the time-frame envisaged, and the 'low hydro' option wherein a lesser number of hydro projects would be included in the mix, owing to financial and other constraints

(ii) Two alternative assumptions were made regarding forced outage rates—a 'high FOR' level and a 'low FOR' level

(iii) In respect of Northern and Western regions, the alternative of 'suppressed pithead generation' was tested to examine divergent views on the economics of pithead versus load-centre thermal generation

To illustrate the type of alternative options

considered, those pertaining to the Northern region are listed below:

(1) High hydro/high FOR

(2) Low hydro/high FOR

(3) High hydro/low FOR

(4) Low hydro low FOR

(5) Suppressed generation of thermal plants located at pitheads and allowing full generation of load centre-based thermal plants corresponding to high hydro/ high FOR scenario

(6) Suppressed generation of thermal plants located at pitheads and allowing full generation of load centre-based thermal plants corresponding to low hydro/ high FOR scenario

As it is not practical to reproduce here the detailed analysis carried out (Central Electricity Authority, 1983, vol II), the type of input data for the various WASP modules is briefly summarised, along with an indication of the nature of results of the generation optimisation studies.

The three data modules in WASP are LOADSY, FIXSYS and VARSYS In LOADSY, the number of periods per year has been taken as 4 The annual peaks, the ratio of the period peaks to the annual peaks (for each year of the study), and the load duration curves being available from the CEA's own projections (Central Electricity Authority, 1983, chapter IV), have been used in this module to create further data files for CONGEN, MERSIM and DYNPRO In FIXSYS, all existing plants as on 31 March 1981 (the first year of the study being the national financial year 1981-82, beginning on 1 April 1981), all sanctioned plants (representing investment decisions taken by the government) and those under construction have been taken as 'committed' Other information relates to the operating features (heat-rates, maintenance requirements, etc) of all thermal units, and of the 'composite hydro system'. In VARSYS, hydro, thermal and nuclear plants considered as expansion candidates during the period 1985-86 to 1994-95 have been described in the data file created by the module (the information in respect of thermal plants is similar to that of FIXSYS).

To illustrate the input data for the CONGEN module, actual data used in the 13th run of CONGEN, corresponding to the optimal solution for high hydro/high FOR scenario for the northern regional system, are summarised below:

(i) Number of VARSYS plants = 8 (4 thermal, 2 nuclear and 2 hydro)

(ii) LOLP constraint = 274 percent for the period 1985-1995

(iii) Reserve margin range = from 0 percent to 50 percent for 1981-85, 10 percent to 50 percent for 1990-95

(iv) Maximum tunnel widths = ranging from 0 to 4 for different years of the study period

(v) Total acceptable configurations (adding up the year-wise numbers) = 618 in this run

The MERSIM module has been explained in detail earlier

In the DYNPRO module, the following numerical values (not exhaustive) have been assigned to various economic parameters

(i) Reference year for discounting = 1981

(ii) Discount rate to be applied to capital investment cost = 8%/year

(iii) Discount rate for operating costs = 8%/year

(iv) Economic plant life thermal and nuclear plants = 35 years hydro plants = 50 years

(v) Cost of energy not served (assumed) = 0

(vi) Maximum permissible LOLP = 1%

(vii) Capital costs have been arrived at on the basis of information available at the commencement of the study for thermal, nuclear and hydro projects included as expansion candidates.

■ **Results of generation optimisation studies**

As mentioned earlier, the generation optimisation studies have been carried out *region-wise*. The two-step approach adopted for generation and transmission has also been outlined earlier. Continuing with the Northern region for illustration, the features of this region have been stated as: (a) large hydro resources were concentrated in the Himalayan region in the North/ Northwest and coal resources were located in the Southeastern fringe in one coalfield, (b) some of the constituent states did

not have much conventional energy sources and had to depend for their power supply either on hydro resources (in the northern region) or on coal or power transported over long distances, (c) the bulk of the power demand was concentrated in the central part of the region, (d) existing installed capacity in the region, as on 31 March 1981, was 9,511 MW almost equally divided between hydro and thermal, with a small (440 MW) nuclear component, and (e) 13,000 MW had been sanctioned/ under construction (nearly 60 percent thermal, 3 percent nuclear, and the rest hydro) to provide benefits during the coming years up to 1995.

The optimal additions to generating capacity have been worked out, corresponding to the different scenarios outlined The following conclusions emerged from these studies. (a) under the high hydro option, the bulk of the additional requirements, especially in the period 1990-95, could be met from hydro, (b) the high hydro-low FOR option, irrespective of thermal plant location, would result in the lowest cost among the various alternatives, (c) the nuclear generation option formed a small proportion of the optimal mix in most scenarios, and (d) the significant impact of improving thermal plant availability was highlighted—an improvement in overall availability by 10 percent indicated to reduce capacity addition requirements by nearly 16 percent.

The Korean case

The Korean power system has grown very rapidly during the last two decades From a total installed capacity of 367 MW in 1961, the Republic of Korea increased it twenty-two-fold by 1979, when the capacity stood at more than 8,000 MW At present, there is heavy concentration of generating facilities as well as load, in the Northwest (Seoul) and the Southeast (Pusan) areas These two areas represent nearly 76 percent of the total load and also have nearly 73 percent of the total generating capacity While the system contained only hydro and thermal units (with negligible internal combustion capacity) in 1961, the nuclear capacity in 1979 was 587 MW, with further additions in the pipeline Transmission line capacity also has gone into the higher voltage of 345 KV, which was non-existent in 1961 (Korea Electric Power Corporation, 1979). Nuclear capacity is expected to go up several-fold during the current decade, reaching over 7,000 MW A policy decision has also been taken by the Korea Electric Power Corporation (KEPCO) not to instal more oil-fired power plants for *baseload* generation Some diesel-fired units/gas turbines will meet part of the peak load, which is also expected to be met substantially by increased hydro-electric capacity, including pumped storage facilities

Korea has applied WASP to develop its generation expansion plan This is briefly summarised here (Argonne National Laboratory, 1980).

The long-term planning time-frame used by KEPCO is twenty-five years In using WASP, KEPCO has estimated a forced outage rate (FOR) for each plant, based on the respective operating history/characteristics The FOR varies from three days per year (for small peaking units) up to 18 days a year (for large baseload plants) Scheduled outage rates, also an input to planning, range from 23 to 77 days per year

As far as other operating features are concerned, Korea has used an LOLP of one day per year in its long-term planning The projected operating reserve margins range from 13 to 20 percent

Generating facilities through 1986 and beyond were planned using the WASP computer code

Plans for future generating facilities, while *not* including oil-fired facilities for baseload generation, include hydro-electric facilities (multi-purpose) and pumped storage

Additional nuclear facilities emerge as an important part of the optimal expansion programme, this reflects a major policy decision to develop nuclear power as a substitute for imported oil In case problems of nuclear fuel arise, Korea may have to consider alternatives such as the use of imported bituminous coal for baseload thermal generation This is mentioned here only to illustrate the point that policy-makers will have to apply qualitative judgements to changing national or international situations, and modify the optimal plans from time to time For instance, the inputs to the VARSYS module will reflect the changing economics of nuclear versus coal-based thermal plants in the changed situation mentioned. Similarly, the economics of pumped storage are dependent on the availability of cheap off-peak power, which scenario can change if there is reduction of nuclear power facilities

In the Korean study, plant life has been assumed as follows: 50 years for hydro plants, 30 years for thermal plants and 20 years for gas turbines The discount rate used has been 10 percent

5 The EGEAS investment planning models

In this section, an outline of three models which have been recently prepared by the Massachusetts Institute of Technology for the Electric Power Research Institute (EPRI) are given. These models are known as the 'Electric Generation Expansion Analysis System' (EGEAS) Space does not permit a detailed analysis and interested readers may refer to the EGEAS reports available with the EPRI (EPRI, 1982, vols 1 and 2).

The models discussed in this section are:

(i) Linear programming analysis option (LP),

(ii) The generalised Benders' decomposition option (GB), and

(iii) The dynamic programming analysis option (DP).

As in WASP, all three models have the same basic objective of minimising investment and operating costs, discounted to the base year specified by the user.

As far as investment costs are concerned, existing and committed units' capital charges are *not* included since these are sunk costs for planning purposes. In regard to operating costs, the linear programming option does not include existing units, as this option uses a fixed capacity factor assumption (user-specified), that is, the energy generated by each unit is determined as a linear function of generating capacity In the case of the GB and the DP options, however, the treatment of operating costs is based on a probabilistic approach Hence, the variable costs of the existing/committed system also enter the optimal calculations.

The three models have their own approach to representation of constraints and reliability. In the LP option, minimum reliability levels are imposed by reserve margin constraints specified for each year of the planning period. Constraints can also be specified in the LP model regarding the maximum and minimum cumulative capacity of a particular generating type that may be installed in a particular year. In this option, thermal, hydro or other limited energy units (such as storage units) can be taken into consideration. A limitation on modelling these alternatives in the LP option is that the LP algorithm requires linearity both in the objective as well as in the constraint specification and therefore, uses a deterministic production cost approach However, there are savings in computational efficiency and simplicity, despite some loss of modelling accuracy.

GB is a sophisticated algorithm based on the iterative use of a simplex algorithm for a master capacity decision problem, coupled with a set of detailed non-linear probabilistic production costing sub-problems As far as constraints and reliability representation are concerned, the GB algorithm has two sets of constraints firstly, pre-specified constraints formulated before any iteration and, secondly, constraints introduced by the programme during iterations The pre-specified constraints reduce the amount of calculation by setting limits on maximum reserve margins and on the amount of capacity of different types to be installed. The 'plant alternative' constraints (also known as tunnel constraints) are of the type discussed in connection with the WASP programme and restrict the cumulative capacity of an alternative installed by a certain year in the planning period, conforming to certain user-specified minimum and maximum values The second set of iteration-generated constraints are run to reduce non-linear relationships in operating cost/reliability For instance, the reliability constraint in the GB option (for each year) is that expected unserved energy is user-specified energy generation level This is the probabilistic criterion of *expected* unserved energy, which is to be met by the optimal expansion plan It will be clear that this approach is closely related to the LOLP approach which has been discussed in the WASP programme

The DP option solves the same planning problem by selecting from all possible alternative combinations, in each year, the minimum cost decision from one year to the next, utilising standard dynamic programming techniques. It will be recalled that dynamic programming is also at the heart of the WASP computer code

In the DP option, operating costs of existing/committed as well as new units are determined via a probabilistic production-cost simulation approach, and form part of the objective functions. There are reliability and tunnel constraints in this option as well. The reliability constraints for each year of the planning period are three minimum reserve margin, minimum LOLP and minimum unserved energy. It will be noticed that the LOLP constraint is additionally imposed in the DP programme, while the 'minimum unserved energy' constraint is similar

the GB option

Among the three EPRI options that have been discussed, the DP option includes the most extensive modelling of the production-costing/reliability aspects of the expansion problem The shortcoming of the GB option in this respect is that it does not include detailed sub-period analysis The LP option, of course, suffers from the fact that production-costing is done on deterministic basis, and to that extent lacks realism Some major points of comparison are worth noting The DP option can simultaneously analyse five expansion alternatives for any one year, while the other two options can analyse a considerably larger number of alternatives without excessive computational requirements As far as storage units are concerned, the DP and GB options treat these more adequately than the LP model in the context of the probabilistic production-costing approach (in this case, the sub-yearly production-costing capability of the DP option makes for more accuracy) It may also be mentioned here that investment in LP/GB options is treated in terms of continuous variables This means that the optimal investment schedule in both LP and GB options can contain fractional unit mixes In contrast, the DP option deals with discrete (integer) variables, thus making the results more realistic

It has been suggested in the EPRI report that the LP option could perhaps be used as a pre-screening device to reduce computations in the other options, which may be used in the subsequent stages to decide on an optimal investment plan from among a set generated by the LP option

MNI model of Electricite de France (EDF)

France has had a long history of utilising mathematical models in power system planning Summarised here briefly is the MNI (national investment) model currently being used for long-term generation planning [7]

The objective of the MNI model is to minimise the total of investment costs, expected generation (operating) costs, and expected outage costs—discounted at a given rate The MNI model has continuous variables only and, in its simplest form, its objective function is written as follows:

$$\min \sum_{t=1}^{T-1} = \left[\sum_i J_i^t U_i^t + G^t\left(X^t + U^t\right) + D^t\left(X^t + U^t\right) + S^T\left(X^T\right) \right]$$

Equation 24

subject to

$U_i^t \geqslant 0$, $X_i^{t+1} = X_i^t + U_i^t$ and
X_i^0 = initial *known* state

where J_i^t is discounted unit investment cost of plant of type i in year t, U_i^t is additional capacity of type i commissioned in year t, $G^t(X^t + U^t)$ is expected discounted operating costs during year t given the system structure $X^t + U^t$ in that year, $D^t(X^t + U^t)$ is expected discounted outage costs during year t for the system structure $X^t + U^t$ and $S^T(X^T)$ is end effects adjustment

In the MNI model, estimates for capital costs/operation and maintenance costs/fuel prices are deterministic data, while demand/hydrological conditions/ unscheduled plant outages are random variables

The constraints on the optimisation are expressed as upper and lower bounds on admissible generation additions for each generation alternative It should be mentioned that reliability enters the optimisation exercise *not* in the form of an LOLP constraint, but as part of the cost function in the form of outage cost computed for the unsupplied energy

Time horizon Each of the first fifteen years are represented by one time-step. and the following years by time-steps of 3 or 5 years Thus, a time horizon of 40 to 50 years can be used with reasonable computation requirements

Method of solution The MNI long-term generation expansion problem is formulated with continuous variables as an optimal control problem using Pontryagin's maximum principle (Electricite de France,) This is a simple discrete optimal control problem In equation 24, the operating and outage cost items G^t and D^t are themselves results of the medium-term stochastic production model with fixed equipment

Optimality conditions· Using Pontryagin's maximum principle, the optimality conditions are now formulated in the simplest case where the only constraint on U_i^t is as follows.

$$U_i^t \geqslant 0$$

7 *There are three othe models which conside specific sub-problem of the power systen viz., 'chain P fa medium-tern production-costing 'RELAX' for medium term maintenance an refueling of nuclea PWR units, an ENTRET for medium term maintenance o conventional therma plants*

The dynamic problem can be split into several static problems The Hamiltonian is as follows

$$H^t = -\left[\sum_{i=1}^{n} J_i^t U_i^t + G^t\left(X^t + U^t\right) + D^t\left(X^t + U^t\right)\right] + \sum_{i=1}^{n} \psi_i^{t+1} U_i^t$$

Equation 25

The adjoint system is:

$$\psi_i^{t+1} = \psi_i^t + \frac{\delta G^t}{\delta X_i^t} + \frac{\delta D^t}{\delta X_i^t}$$

$$\psi_i^T = -\frac{\delta S}{\delta X_i^T}$$

Equation 26

It can be solved as follows.

$$\psi_i^t = -\sum_{\zeta=t}^{t-1}\left[\frac{\delta G^\zeta}{\delta X_i^\zeta} + \frac{\delta D^\zeta}{\delta X_i^\zeta}\right] - \frac{\delta S}{\delta X_i^T} \quad (i = 1 \text{ to } n)$$

Equation 27

The optimal control is given by maximisation of the Hamiltonian function given above

$$\text{Max}\left[\sum_{i=1}^{n}\left(\psi_i^{t+1} - J_i^t\right)U_i^t - G^t\left(X^t + U^t\right) - D^t\left(X^t + U^t\right)\right]$$

$$U_i^t \geq 0$$

Equation 28

Using the Kuhn-Tucker theorem,

$$\psi_i^{t+1} - J_i^t - \frac{\delta G^t}{\delta U_i^t} - \frac{\delta D^t}{\delta U_i^t} = 0, \text{ if } U_i^t > 0$$

Equation 29

$$U_i^t = 0, \text{ if } \psi_i^{t+1} - J_i^t - \frac{\delta G^t}{\delta U_i^t} - \frac{\delta D^t}{\delta U_i^t} < 0$$

Equation 30

In the following formulation,

$$\psi_i^t = -\sum_{\zeta=t}^{T-1}\left[\frac{\delta G^\zeta}{\delta X_i^\zeta} + \frac{\delta D^\zeta}{\delta X_i^\zeta}\right] - \frac{\delta S}{\delta X_i^T}$$

$(i = 1 \text{ to } n)$

Equation31

the component ψ_i^t of the co-state vector appears as the total future savings of [operating cost plus outage costs] provided by the additional KW of plant i at time t. Therefore, ψ_i = value of equipment i at time t.

Net marginal gains

The Kuhn-Tucker conditions for maximising the Hamiltonian with respect to U^t have already been given above.

Since G and D are functions of $(X^t + U^t)$, we have

$$\frac{\delta G^t}{\delta X_i^t} = \frac{\delta G^t}{\delta U_i^t} \qquad i = 1 \text{ to } n$$

Equation 32

$$\frac{\delta D^t}{\delta X_i^t} = \frac{\delta D}{\delta U_i^t}$$

Equation 33

The Kuhn-Tucker condition (equations 29 and 30) becomes

$$\psi_i^{t+1} - J_i^t - \frac{\delta G^t}{\delta X_i^t} - \frac{\delta D^t}{\delta X_i^t} = 0 \text{ if } U_i^t > 0$$

$$U_i^t = 0 \text{ if } \psi_i^{t+1} - J_i^t - \frac{\delta G^t}{\delta X_i^t} - \frac{\delta D^t}{\delta X_i^t} < 0$$

$[i = 1 \text{ to } n]$

Equation 34

Taking the dual system (equation 26) into account,

$$\psi_i^{t+1} = \psi_i^t + \frac{\delta G^t}{\delta X_i^t} + \frac{\delta D^t}{\delta X_i^t}$$

Equation 35

and substituting into (equation 34) above,

$$\psi_i^t - J_i = 0 \text{ if } U_i^t > 0$$

$$U_i^t = 0 \text{ if } \psi_i^t - J_i^t < 0$$

Equation 36

The above shows that, at the optimum, the unit investment cost and unit use value of the equipment are equal This is the same as the long-run marginal cost The capability of the MNI model to calculate LRMC at the optimum is of very great benefit to EDF which uses marginal cost pricing for the formulation of its tariff policy

In the French system, the generation system expansion is determined, first, on the implicit assumption that generating facilities and load centres are concentrated at the same point, and, at the second stage, network expansion is added, with iterations being carried out between these two steps as necessary. EDF believes that this

nposition approach is justified in France use (a) the network has adequate connections, (b) the lead-time for mission lines is shorter than that for ration plants, and (c) total investment costs ransmission are much smaller than those uired for generation It will be observed that a ar iterative approach is followed in the ian and Korean systems as well

imitations of models

hile generation expansion planning models eing used in many developed countries and lowly gaining acceptance among planners in loping countries, there are several aspects erning their use which require mention here

irstly, the mathematical nature of models give a misleading impression of precision in rea where precision is hard to come by, ly because of the uncertainty attached to the viour of many of the variables The policy ner can make allowance for this feature by ulating several alternative scenarios [8] *ondly*, the planner has to see that the traints/assumptions of the model are istic as far as his country is concerned For ance, a very high reliability criterion (of, say, levels) may not be the correct figure to build the model of a developing country, as the optimisation exercise would then result in considerable excess capacity in off-peak hours and add significantly to costs Many of these assumptions obviously depend on qualitative judgements based on a country's requirements, objectives and resources *Thirdly*, the quality of available data of different types are an important limitation on the use of these models.[9] It would, of course, be defeatistic to avoid using quantitative aids until the data base of the country improves, but it would be useful to bear this limitation in mind *Fourthly*, all the models discussed relate directly only to *generation* expansion In many countries (India, for example), where load centres are far away from coal mine areas, high voltage transmission over long distances constitutes a very significant cost A two-stage iteration exercise is performed in such cases, as discussed earlier Depending upon the number of iterations/scenarios, this process can add considerably to computation requirements However, this limitation is not a major one for many countries whose transmission costs are not very high in comparison to generation costs *Fifthly*, it could be argued that such computer models are not presently required by small countries, whose power systems present only a few limited expansion alternatives, and also where qualified trained personnel to operate these models may not be readily available This, however, may be resolved by training in the use of some of these models

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8 *For example, optimistic and pessimistic forecasts of demand based on different GNP growth rates, high and low forced outage rates of thermal plants, etc, as discussed in the Indian context earlier*

9 *For instance, data regarding project costs and construction periods of projects of different types have a crucial effect on the optimisation exercises.*

'GENERATION EXPANSION PLANNING - AN OVERVIEW'

BY

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LONG TERM PLANNING
CENTRAL ELECTRICITY AUTHORITY

1. Prior to acquiring the WASP-III long-term generation expansion planning package from the International Atomic Energy Agency, Vienna, Power Planning in the country was done on the basis of deterministic approach. The WASP-III package is based upon probabilistic technique of power system simulation for production costing which is a better way of calculating generation cost as compared to earlier approach. The first national power plan covering the fifteen years period of 1980-95 was prepared in early 1983 using the WASP-III package. Recently the generation expansion planning has been carred out for the period 1985-2000 A.D. using EGEAS and ISPLAN computer packages. The results of these studies are contained in the revised National Power plan published last year.

2. The long-term power planing exercises for generation expansion planning have been done considering the well defined five power regions as the spatial units. The basic philosophy in regional planning is that the regions are considered as self-contained units of power system without hindrances of power flows within the sub systems of the regions. This was considered necessary for optimal utilization of scarce and unevenly distributed energy resources over the geographic area of the country. Dur9ing these studies inter regional exchanges of power was not considered because it was found that at present these are taking place only on a limited scale.

3. The demand projections made by the 12th Power Survey Committee were adopted for these studies. Although various other agencies such as Working

Group on Power, Advisory Board on Energy and Expert Screening Group on Power have also made forecast of the peak demand & energy requirement for the same period. The studies were also conducted to assess the requirements of capacity additions in case the demand growth is less as compared to the projections of 12th EPS report, because the projections made by some other organisations as mentioned above were some what on the lower side as compared to 12th EPS forecast. The demand projections for the country by the turn of the century were 125400 MW corresponding to 685 billion units. The peak demand and energy requirements for the terminal years of 7th, 8th and 9th Plans are tabulated in Table- 1 below.

TABLE-1

Plan	Terminal Year	Peak Demand (MW)	Energy Requirement (Mkwh)
Seventh	1989-90	49278	269379
Eigth	1994-95	78438	428613
Ninth	1999-2000	125400	684973

SCHEMES FOR BENEFITS IN THE EIGHTS & NINTH PLANS

4. The country had a total installed capacity of 42,440 MW (utilities) comprising of 14465 MW of hydro, 26,880 MW of thermal and 1095 MW of nuclear power plants at the end of Sixth Plan. As per the Seventh Plan document, a capacity addition of 22,245 MW has been envisaged during the Seventh Plan. Further, there are a large number of schemes which have been sanctioned or cleared by CEA for giving benefits during the 8th Plan and the 9th Plan periods. These schemes aggregate to about 30,600 MW (sanctioned schemes aggregate to about 21,600 MW and CEA cleared to about 9,000 MW). All these schemes have been considered as committed projects in the optimization studies for evolving the long term optimal power development programme. In addition, a number of new projects have already been identified which could be taken up for benefits in the Eighth Plan and beyond keeping in view their

present state of preparedness and other relevant factors. The studies, therfore, were undertaken to identify such of the new projects which will be required, over and above the committed, projects, to meet the anticipated demand during the Eigth and Ninth Plan periods as the least cost optimall option for generation capacity expansion.

MTHODOLOGY:

5. The basic objectives of long-term power planning is to supply power of adequate quality and reliability at the lowest possible cost. This involves optimal development of generation, transmission and distribution facilities. Because of the limitations of the computer models to handle the entire power systems simultaneously, some parts of the power system are disregarded to keep the problem within manageable limits. Keeping in view of this, the WASP Package did not have facility to consider transmission while optimizing the requirements of generating capacity as may be available from various supply options. Accordingly, the studies contained in the earlier National Power Plan Report of the CEA were based on two-step approach for studying the implications of various alternative generation expansion patterns namely:

First: Several alternative generation expansion patterns were identified and each generation expansion pattern was optimized corresponding to the assumed criteria without taking into account the matching but transmission requirements:

Second: For each alternative optimised generation expansion plan, the bulk transmission facilities that would require were developed by using separate power transmission system planning packes.

The results obtained from the two steps were then synthesised to develop alternative generation and transmission expansion plan and these synthesised results provided the basis for evolving the needed optimal path for expansion of generating capacity in'the system.

6. In the present studies however, a different methodology has been

adopted on account of the facilities available for simulation of generation and transmission systems together while working on both the EGEAS and the ISPLAN models. The EGEAS Model like the WASP Package has the capability of optimizing the various available supply options for satisfying the projected requirement of electricity over the specified time horizon using the dynamic programming algorithm based on probabilistic techniques. On the other hand, the ISPLAN Model is capable of addressing the problem of optimizing the generation mix while taking into account the requirement of additional transmission networks as well. The use of these two models in an inter-active manner, therefore, formed the basis of present optimization studies. The manner in which these two models were used in the studies is briefly described below.

7. The dynamic optimization algorithm of EGEAS Package determines the additional capacity requirements by optimising among the new candidate power projects, over and above the committed capacity (sanctioned projects and the schemes cleared by CEA), to meet the forecasted demand of electricity subject to a desired reliability level in terms of LOLP. In EGEAS Model, however, the number of alternative new power projects which can be simultaneously considered for optimization are limited to a maximum number of ten. As such, the new power projects have similar technical and economic features were, therefore, grouped together to be within the overall maximum permissible limits of EGEAS Package. The results of the Optimization studies thus, obtained indicated the required optimal capacity additions from various modes of generations during the time horizon of the study. Thus, the plication of EGEAS Model resulted in determining the optimal mix of generation from various available supply options by years covering the period of study, subject to specified system LOLP to meet the assessed electricity demand projections.

8. The next requirement of identifying the individual power projects corresponding to the optimal generation expansion plan indicated by the EGEAS optimization programme was met by fixing the interse priority of various available projects using ISPLAN Model which, as already mentioned, has the capability to address simultaneously the problems of determining the optimal generation mix and the plant locations by considering the transmission network requirements of power system as well. Various new power projects in ISPLAN Model are represented as specific power projects alongwith their broad techno-economic characterisitcs, like cost of delivered coal at each power station, their proposed linkage to coal-mines, the future indicated transmission links from the new power projects to the exising transmission grid, location of power plants on coal transportation network and maximum permissible installed capacity at each specific site. The ISPLAN Model selects the most economical power plants among the various new available power projects using linear programming techniques of optimization and simultaneously taking into account the above factors including the matching transmission requirements.

9. Thus, while the EGEAS Model was used to determine optimal quantum of required capacity inductions from various model of available generation during the study period, the ISPLAN Model was used to select the individual new power plants from various modes of power generation based on considerations of matching transmission networks requirements. The results of the two studies were then synthesised to obtain the precise list of new power projects which would be required in the region over and above the committd pojects to meet the projected demand of electricity subject to the specified level of system reliability (LOLP).

OPTIMAL GENERATION EXPANSION PLAN

10. Optimisation studies carried out with the help of the above two computer programmes have indicated that the country will need to add additional 46,684 MW of capacity during the 8th Plan and 61,307 MW during the 9th Plan i.e. a total addition of 108,000 MW of capacity during the period 1990-2000 (which would raise the installed capacity to 174,649 MW by the turn of the century), if the projected demands have to be met with a somewhat reasonable quality of power supply (with loss of load probability of 5%). If we were to aim at still higher reliability level of say, 1% LOLP, as was assumed in the first National Power Plan, 1983, it would be necessary to add 125291 MW of new capacity during the 8th and 9th Plan periods which would raise the total installed capacity to 191,949 MW as would be seen from the table given below:

CAPACITY REQUIREMENT FOR VARIOUS RELIABILITY LEVELS

Reliability/ LOLP	I.C. at the end of 7th Plan (MW)	Additions required during 8th Plan (MW)	9th Plan (MW)	Total during (1990-2000) (MW)	I.C. at the end of 9th Plan (MW)
1%	66658	56384	68907	125291	191949
5%	66658	46684	61307	107991	174649
10%	66658	39584	59357	98941	165599

11. This level of capacity addition (125291 (MW) corresponding to LOLP of 1%, during the decade is considered to be too high a target, not only fromm the financial considerations but even from other considerations like organisational capability to add about 12,000 to 13,000 MW of capacity annually. As such all the detailed studies have been done to realise a system reliability level between 1% and 5%. The required capacity addition of 108,000 MW corresponding to the optimisation plan with 5% LOLP will comprise of 39,499 MW of hydro, 60,202 MW of thermal and 8,290 MW of nuclear plants. The region-wise capacity addition during the 8th and 9th Plan periods are given below:

Regions	Capacity Additions (MW)				Installed Capacity (MW)
	Hydro	Thermal	Nuclear	Total	
8th Plan					
Northern Region	8318	4760	470	13548	33093
Western Region	5709	5540	1440	12689	32551
Southern Region	2354	7600	1440	11394	27541
Eastern Region	1247	6920	-	8167	17833
North-Eastern Region	444	442	-	886	2301
ALL-INDIA:	18072	25262	3350	46684	113342

Regions	Capacity Additions (MW)				Installed Capacity (MW)
	Hydro	Thermal	Nuclear	Total	
9th Plan					
Northern Region	8588	9280	1970	19838	52931
Western Region	2900	12100	1470	16470	49021
Southern Region	5574	6000	1500	15074	42615
Eastern Region	4110	5500	-	9610	27443
North Eastern Region	255	60	-	315	2616
All-India	21427	34940	4940	61307	174649

12. These capacity additions have been planned to be realised from the various Schemes* as under:

(As in June,1986)

	Hydro	Thermal	Nuclear	Total
Sanctioned Schemes	6808	9830	470	17108
CEA Cleared Schemes	9671	6562	-	16233
New Schemes	23020	43810	7820	74650
Total:	39499	60202	8290	107991

* At the time of start of the studies, in June,1986 sanctioned schemes had aggregated to 17,108 MW and CEA cleared schemes to 16,[illegible]3 MW. At present there are sanctioned schemes over 21600 MW and CEA cleared schemes totalling about 9000 MW (as on 1.4.1987).

With the addition of these schemes, the reliability level (LOLP) of the power systems in the various regions ranges from 9% to 28% by the end of 7th plan would improve to about 5% by the turn of the century.

HYDRO-THERMAL-NUCLEAR MIX

13. The hydro-thermal mix on an All-India basis at the end of Sixth Plan was 34.1% hydro and 65.9% thermal including [illegible]out 3% nuclear. According to the present assessment, the hydro-ther[illegible] mix on an All-India basis at the end of 7th Plan period is expecte[illegible] be 30%, 67.3% and 2.7%. As per the optimal plan the hydro:thermal mix is expected to improve to 34% hydro, 66% thermal including 3.5% of nuclear capacity by the end of the 9th Plan. The region-wise mix of various generating capacities at the end of 6th, 7th and 9th Plan periods is given hereunder:-

	Sixth Plan			Seventh Plan			Ninth Plan		
	Hy.	Th.	Nu.	Hy.	Th.	Nu.	Hy.	Th.	Nu.
Northern	42.2	54.1	3.7	33.8	61.5	4.7	44.5	49.2	6.3
Western	14.1	82.7	3.2	13.8	84.1	2.1	23.1	70.1	6.0
Southern	61.2	36.5	2.3	52.5	44.6	2.9	38.5	53.5	8.0
Eastern	15.1	84.9	-	16.9	[illegible]	-	25.5	74.5	-
North-Eastern	39.6	60.4	-	38.7	61.3	-	47.7	52.3	-
All-India:	34.1	62.9	3.0	30.0	67.3	2.7	34.1	60.1	5.8

14. It will be seen from the above that the hydro-thermal-nuclear mix may be expected to be about 44.5%, 49.2% and 6.3% in the Northern region, 38.5% 53.5% and 8.0% in the Southern region and 47.7%, 52.5%(Th.)in the North-Eastern regions which is considered to be quite satisfactory. The percentage of hydro capacity on the All-India basis is expected to be still much lower than the desirable level even at the end of 9th Plan period. The lower hydro: thermal mix is mainly due to very low hydro-thermal mix in the Eastern Region (25.5% hydro by the end of the 9th Plan) and Western region (23.1% hydro by the end of the 9th Plan). Some of the projects which were considered for these optimisation studies have not been accepted by the Model in view of their very low load factor, assumed on the basis of project reports and the other indications from concerned States. Further optimisation studies of these two regions have indicated that the systems in these regions would have accepted many more hydro plants if these were available with comparatively higher energy potentials for giving benefits

during the pperiod under consideration. In case, therefore, if these schemes could be reviewed and re-cast for operation at higher load factor, these are likely to get accepted in the subsequent optimisation studies, consequently improving the hydro-thermal mix in the regions. The poor hydro-thermal mix in these two regions therefore could not be helped because of lack of availlbility of such hydro projects which could give benefits within the considered time-frame. These studies have highlighted the need for immediate advance action on a large number of hydro schemes to bring them to such a state of readiness so that sufficient number of projects are available for giving benefits atleast during the 10th Plan and beyond if not earlier. In view of the very large hydro potential available in the North-Eastern region and also since there is very little possibility of using this huge potential within the region in the near future, it will probably be most desirable to integrate operation of the North-Eastern region and the Eastern region to increase the operational economy and efficiency of these two systems. Incidentally, this will also serve as the first important steps towards the integrated operation of all the Regional Power Systems in the country and ultimate evolution of the National Grid. This will also help to substantially improve the hydro-thermal mix in the two regions as well as enable better utilisation of the hydro resources in the North-Eastern region.

FEASIBLE-CUM-DESIRABLE GENERATION EXPANSION PLAN:

15 Close examination of these optimisation results in terms of reasonably even distribution of generation capacities keeping in view the State's requirements and also considering the practicability of adding new hydro projects for giving benefits in the 8th and 9th Plan period etc.

indicated the need for certain modifications in the optimum plan. Hence, desirable changes were introduced and a more pragmatic feasible-cum-desirable programme for each region has been evolved. Even though this modified plan does not envisage optimum operating conditions, these modifications were particularly considered necessary in view of the very restricted activity in a number of hydro projects during the 7th Plan period, which has affected the probability of their giving benefits during the 8th and 9th Plan period. The desirable plan will require an additional capacity of about 2000 MW over and above the capacity requirements under the optimal plan to meet the same projected demand with the same reliability level because of somewhat lower hydro power content.

16. While the reliability level of each region has been kept around 5% in this feasible-cum-desirable plan, the hydro-thermal mix has come down slightly as compared to the optimal plan. The likely overall All-India hydro-thermal and nuclear mix of 30%, 67% and 3% at the end of the 7th Plan is likely to only marginally improve to 31%, 66% and 3% by the turn of the century. The total capacity additions as per the desirable plan, would be 48,056 MW during the 8th Plan period and 62,099 MW during the 9th Plan period, bringing the total installed capacity to 1,76,813 MW. Regionwise capacity additions during the 8th and 9th Plan periods, as per the feasible-cum-desirable plan, are given below:

Region	8th Plan (MW)				9th Plan (MW)			
	Hy.	Th.	Nu.	Total	Hy.	Th.	Nu.	Total
Northern	6483	7470	470	14423	9028	9570	970	19568
Western	3633	9170	470	13273	3905	11162	970	16037
Southern	2367	8330	470	11167	4876	9600	970	15446
Eastern	1267	7040	-	8307	3043	7690	-	10733
North-Eastern	444	442	-	886	255	60	-	315
All-India(Total):	**14194**	**32452**	**1410**	**48056**	**21107**	**38082**	**2910**	**62099**

BULK TRANSMISSION FACILITIES

17. The requirement of transmission facilities for evacuation of bulk power from generating centres to consuming points have been estimated on a global level based on 'ISPLAN' model studies which makes use of the concept of DC flow estimation to evolve an indicative configuration of transmission system. The broad conclusions based on these studies indicate that following corridors having a capacity of 1000 MW and above would have to be established within the time-frame under consideration:

Northern Region	1. Muzaffarnagar	Rishikesh
	2. Tehri	Muradnagar
	3. Naptha Jhakri	Abdullahpur
	4. Baglihar	Udhampur
	5. Auriya	Agra
	6. Salal	Jammu
	7. Agra	Ballabgarh
Western Region	1. Sardar Sarovar	Asoj
	2. Narmada TPS	Nardipur
	3. Trombay	Kalwa
	4. Indore	Ujjain
	5. Vindhyachal	Koradi
	6. Asoj	Karamsad
	7. Burwaha	Indore
	8. Itarsi	Indore
	9. Koradi	Bableshwar
Southern Region	1. Mangalore	Mysore
	2. Vijayawada	Manguru
	3. Kalinadi	Hubli
	4. Rayalseema Region	Hyderabad
Eastern Region	1. Talcher	Bhanjnagar
	2. Tenughat	Talcher
	3. Ib TPS	Rourkela

18. The line capacities etc., will have to be, however, established based on subsequent detailed power system studies. The CEA is already engaged in evolving such a programme and a detailed plan of bulk transmission for the entire country, would be projected shortly.

FINANCIAL REQUIREMENTS

19. As per tentative estimates, the feasible-cum-desirable power plan would require an investment of Rs. 55,500 Crores for generation schemes (excluding funds required for the Nuclear Programme) during the 8th Plan and Rs. 71,200 Crores during the 9th Plan periods. A break-up of fund requirements in the 8th and 9th Plans etc. is given below:

FUNDS REQUIREMENT* FOR ALL INDIA FEASIBLE-CUM-DESIRABLE GENERATION EXPANSION PROGRAMME

(Rs. Crores)

Types of Schemes	8th Plan	9th Plan
Sanctioned Schemes	6600	200
CEA Cleared Schemes	11600	1400
New Schemes	37300	69600
Total:	55500	71200

* (Excluding funds required for Nuclear Power Programme).

20. A matching investment for transmission and distribution have also to be made to ensure proper evacuation and utilization of power, with reasonable reliability and quality. Based on past allocation of funds between transmission and generation schemes and keeping in view the general pattern of investment in these two areas in other countries, it is felt that the transmission and distribution system may need an investment equal to atleast about 60% to 70% of the investment on generation scheme. On this basis, the total investment for the T&D expansion in the 8th Plan is estimated to be about Rs. 33,300 Crores and about Rs.42,600 Crores in the 9th Plan (excluding funds required for Nuclear Power programme). Thus, the

total investment in the power sector during the 8th Plan would be of the order of Rs.89,000 Crores and during the 9th Plan Rs.1,14,000 Crores. This investment estimate however, includes the funds required on an approximate basis for new schemes on which advance action needs to be taken up during the 8th and 9th Plan periods for giving benefits during the 10th Five Year Plan period and beyond.

POWER DEVELOPMENT STRATEGY - SENSITIVITY STUDIES:

21. Keeping in view the huge requirements of funds to finance the power plan even if the reliability level is aimed at 5% only and the present fund availlbility for the 7th Plan, the availability of required funds cannot be assumed as certain. It was, therefore, considered desirable to make necessary studies by changing various parameters so that the implications of probable changes in the important parameters could be visualised and necessary and suitable steps could be taken to ensure best possible course of development within the stipulated constraints.

IMPACT OF REDUCTION IN DEMAND:

22. The most important parameter is the projected load demand upto the year 2000 A.D on which depends the level of the generation expansion. Hence, studies were made to workout the reduction in the capacity requirement if the demand by the year 2000 could be contained by various means. The studies have indicated that if the peak load and energy demand in the country could be reduced by 10% than the projections of the 12th EPS Committee, the capacity requirements would get reduced by 15,690 MW for the same reliability level of, LOLP of 5% resulting in consequential saving in the overall investment requirements by about Rs. 28000 Crores.

IMPROVEMENT IN PERFORMANCE OF THERMAL PLANTS:

23. Another possibility for reducing the capacity requirements without adversely affecting the system reliability level could be by attempting to improve the performance of thermal power plants by reducing the forced outage and partial outage rates. The studies have indicated that if the equivalent forced outage rate could be gradually reduced by about 25% (from 32% to 24%), the requirement of total installed capacity in the system by the end of the 9th Plan would be reduced by 8000 MW effecting a saving in the overall investment of the order of Rs. 14,000 Crores.

IMPROVEMENT IN SYSTEM LOAD FACTOR:

24. The other possibility of reducing the capacity requirements without affecting the quality of power supply is the improvement in the system load factor by adopting suitable load management practices. The sensitivity studies have indicated that if the peak load could be reduced by 10% as compared to the 12th EPS projections, while maintaining the energy requirements at the projected level, the capacity requirement by the end of the 9th Plan would be reduced by about 9000 MW which will effect saving in the overall investment of about Rs.16000 Crores.

25. Various sensitivity studies conducted have thus clearly revealed that keeping in view the overall financial constraints,(1) the power sector will have to make serious efforts to (i) take requisite measures to reduce the load growth, (ii) improve performances of thermal plants and (iii) improve the system load factor by taking various effective load-management measures; and (2) the overall hydro-thermal mix will not experience any significant improvement unless the country makes concerted efforts without losing any further time for investigation and identification of available

hydro sites, otherwise the situation may still further worsen in the years to come.

ACCELERATED HYDRO DEVELOPMENT:

26. Since improved hydro-thermal mix is extremely important from various considerations including optimum operation of the system with reduced environmental hazards, conservation of depleatable fossil fuels, reductions in overall electricity generation costs which are already becoming prohibitively high, studies were attempted to find out that if the country had taken suitable measures so that the required number of suitable hydro projects were available for giving benefits in the time-frame 1990-2000, what would have been the acceptable level of hydro-thermal mix in accordance with the criteria of optimal operation. These studies have indicated that if the constraint of availability of projects was not there, the share of hydro in various regions for ensuring optimal operation with a system reliability of LOLP of 5% would have been as under:

	Capacity Additions (MW)		%of hydro capacity at the end of 9th Plan.
	8th Plan	9th Plan	
Northern Region	13548	17278	54.3%
Western Region	12689	13970	33.2%
Southern Region	11394	13574	47.2%
Eastern Region	8267	8310	35.1%
N-Eastern Region	886	315	47.7%
All-India:	46684	53447	43.5%
Total (1990-2000):	100131 MW		

27. The total additional capacities required within the decade 1990-

2000 for this would have been of the order of 100131 MW (comprising of 52599 MW of hydro, 39242 MW of thermal in addition to 8290 MW from nuclear plants) as against the capacity requirement of 108000 MW for the same system reliability as per optimal plan. Thus, the capacity addition requirements would have been less by about 8,000 MW. It is obvious that the country would have saved a substantial amount of scarce capital in addition to numerous other advantages of utilising hydro potential if suitable advance action had been taken earlier. It is, therefore, imperative to initiate, atleast now, immediate action to ensure availability of sufficient hydro power projects for giving benefits from 9th Plan onwards.

28. The lack of readiness of hydro power projects for being taken up for construction suggests the need for positive action and organisationalsupport for carrying out expeditious and timely investigations. It is felt that if the large number of hydro projects, most of them now being located in remote hilly areas, are to be timely investigated, suitable action for centralising the investigation process and modernising the investigation techniques with arrangement of suitable equipment for the purpose would be essential. The Centre may have to take necessary steps to create separate fund to take up and expedite hydro project investigations. The gestation period for hydro project construction also needs to be reduced substantially by modernising the construction processes and by using modern equipments. It may be worthwhile considering a Central agency vested with the responsibility for procuring and maintaining modern costly construction and investigation equipments for leasing them out to the construction and investigating agencies.

29. The environmental issues in the implementation of hydro power

projects are becoming more pronounced. Advance action particularly in case of large hydro power projects involving creation of big reservoirs is essential. Among the probable advance action, afforestation of catchment areas, acquiring land etc. alongwith the investigation itself could be considered. Since, as a result of the extensive hydro electric potential assessment studies conducted by CEA, the location of major hydro schemes involving large reservoirs alongwith their major parameters are already identified, suitable machinery could be created at Central level for taking advance action so as to reduce the adverse environmental effects at the time of taking up of the projects. This may include avoiding taking up any developmental work in the project area and adopting deliberate policies within the project region so as to help natural immigration of the local people to the nearby areas.

STRATEGY FOR THERMAL POWER DEVELOPMENT:

30. Since the power development activity in the coming two Five Year Plans will involve major addition of thermal power projects, the power sector needs to take suitable action to solve some of the expected problems including consistency and quality of coal supply, adequate availability of water,particularly at pit head,capacity concentrations like Singrauli, etc., pressure on the conventional system of coal transportation, increasing pressure on land and water uses and increasing awareness of the environmental problems due to thermal power development. In this connection, urgent action for finding suitable means for economic disposal of ash is also important.

- -

CENTRAL PARTICIPATION:

31. The Central generation in the overall installed capacity in the country would continue to increase during the period . The share of central generation would increase from about 15000 MW (22.5%) by the end of the 7th Plan to about 32000 MW (28%) by the end of the 8th Plan and further to about 53000 MW (30%) by the end of the 9th Plan. In view of the fast increasing role of centre in the power generation, the question of re-organising the central sector generating companies may need to be reviewed. Such a step is also essential with a view to keep such organisations within limits of economic functioning.

REGIONAL OPERATION OF POWER SYSTEMS:

32. The present planning exercises have been done on the premise of regional operation of power systems. Although, physical integration of the contiguous systems in a region has been achieved, the functional integration is beset with competing philosophies of economic and commercial issues. These problems are surfacing particularly in the areas of tariff making. These are, however, not unsurmountable difficulties and it is believed that concerned authorities can and will take effective steps to achieve full functional integration of the systems within regions so as to achieve the full advantages of the regional planning.

33. Considering the uneven distribution of power resources and the increasingly large sizes of power systems in each region, it appears desirable to take positive steps towards integrating even the regional grids. The integrated operation of Western and Southern regions and/or North-Eastern and Eastern Regions could probably be a beginning towards this end.

ELECTRIC POWER RESEARCH INSTITUTE

EGEAS EDIT VER 02 LEV 02 WESTERN REGION

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EEEEEEEE     GGGGGG     EEEEEEEE    AAAAAA      SSSSSS
EEEEEEEE    GGGGGGGG    EEEEEEEE   AAAAAAAA    SSSSSSSS
EE          GG    GG    EE         AA    AA    SS
EEEEEEE     GG          EEEEEEE    AAAAAAAA    SSSSSSS
EEEEEEE     GG   GGG    EEEEEEE    AAAAAAAA     SSSSSSS
EE          GG    GG    EE         AA    AA          SS
EEEEEEEE    GGGGGGGG    EEEEEEEE   AA    AA    SSSSSSSS
EEEEEEEE     GGGGGG     EEEEEEEE   AA    AA     SSSSSS
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ELECTRIC GENERATION EXPANSION ANALYSIS SYSTEM

EDIT PROGRAM

ELECTRIC POWER RESEARCH INSTITUTE
3412 HILL VIEW AVENUE
PALO ALTO, CALIFORNIA 94304

GENERAL DATA

BASE YEAR . . . . . . 1988 DISCOUNT RATE . . . .
ALL DATA BASE COSTS (PERCENT)
ARE IN 1988 DOLLARS

NUMBER OF DAYS PER YEAR . 364
NUMBER OF HOURS PER YEAR . 8736

NUMBER OF CUMULANTS . . .
USED IN REPRESENTING PLANT
OUTAGES AND LOAD CURVES

UNSERVED ENERGY COST . . 2000.00 RS/MWH
YEARLY ESCALATION TRAJECTORY 15
INTERCONNECTED SYSTEM SERVICE AREA SYSA

SYSTEM RELIABILITY CONSTRAINTS

DATA SET REF. NO.	FIRST YEAR CONSTRAINTS USED	...RESERVE MARGIN... MINIMUM PERCENT	MAXIMUM PERCENT
1	1988	30.00	100.00

EXPECTED LOSS OF LOAD HOURS/YEAR	EXPECTED UNMET ENERGY PERCENT	SPINNING RESERVE OPT	REQUIREMENT
876.00	10.00	2	10.00 PCT(PEAK UNIT)

SYSTEM DEMAND

IN BASE YEAR 1988 -

PEAK LOAD . .	11060. MW
ENERGY . .	62082. GWH

YEARLY ESCALATION TRAJECTORIES

PEAK LOAD . .	9
ENERGY . .	10

ADJUSTMENT OPTION . . AL
USED IN RESOLVING INCONSISTENCIES
AMONG PEAK, ENERGY, AND LOAD SHAPE

LOAD CURVES

DATA SET REF. NO.	FIRST YEAR CURVE USED	ORTHOGONAL. LOAD PTR.	LOAD FACTOR	MINIMUM LOAD FRACTION
1	1988	1	.744340	.472134

LOAD DURATION CURVE

1.00000000	1.00000000	1.00000000	1.00000000	1.00000000
1.00000000	1.00000000	1.00000000	1.00000000	1.00000000
1.00000000	1.00000000	1.00000000	1.00000000	1.00000000
1.00000000	1.00000000	1.00000000	1.00000000	1.00000000
1.00000000	1.00000000	1.00000000	.99864602	.998220[illegible]
.99774539	.99557316	.99053337	.98050869	.96350572
.92506195	.88297153	.82198405	.74946725	.67224789
.59810616	.50853344	.41921453	.34081346	.26737185
.20110396	.14371130	.10275139	.06996909	.04561710
.02540990	.01440540	.00755001	.00365851	.00000000

CUMULANTS

```
.74433970E+00     .77011017E-02     .11948220E-03     -.20757572E-04
-.26636339E-05     .27189702E-06     .98458941E-07     -.53508398E-08
```

DATA BASE CONTENTS REPORT

***

BASIC PLANT TYPES

DATA SET REF. NO.	1			2		
NAME	TROMBAY-5			UKAI EXT-5		
TYPE	THRM			THRM		
LOADING STRATEGY	B			B		
STATUS	E			E		
CLASS	OIL			COAL		
SERVICE AREA	3			SYSB		
POLITICAL SUBDIVISION	MAHA			GUJ		
PERCENT OWNERSHIP	100.0			100.0		
NUMBER OF UNITS GROUPED	1			1		
INSTALLATION YEAR	1984			1985		
RATED CAPACITY (MW)	500.0			210.0		
CAPACITY - RESERVE	1.0000			1.0000		
- OPERATING	.9000			.9000		
MULTIPLIERS - EMERGENCY	.9000			.9000		
- CHARGING	.0000			.0000		
EQUIVALENT FORCED OUTAGE RATE	.3220			.3220		
FULL LOAD HEAT RATE (BTU/KWH)	2565.			2664.		
ANNUAL ENERGY LIMIT (GWH)	.0			.0		
STORAGE EFFICIENCY (PCT)	.00			.00		
DESIGN CAPACITY FACTOR (PCT)	100.00			100.00		
INSTALLATION COST 1 (RS/KW)	.00			.00		
INSTALLATION COST 2 (RS/KW)	.00			.00		
LEVELIZED CARRYING CHARGE (PCT)	.00			.00		
FIXED O&M COST (RS/KW-YR)	.00			.00		
VARIABLE O&M COST (RS/MWH)	25.00			25.00		
OPERATING LIFE (YEARS)	35			35		
BOOK LIFE (YEARS)	0			0		
YEARLY TRAJECTORIES						
COSTS-CAPITAL/FIX OM/VAR OM	0	0	43	0	0	43
FORCED OUTAGE RATE	2			2		
CAPACITY-RESERVE/OPERATING	0	0		0	0	
ENERGY LIMIT /CAP FACTOR	0	0		0	0	
SEGMENT - CAPACITY	0			0		
MULTIPLIERS - ENERGY	0			0		
SUB-WEEK STORAGE ALLOCATION	0			0		
MAINTENANCE DATA SET	1			1		
FUEL DATA SET	16			10		
LOADING BLOCK DATA SET	0			0		
NON-DISPATCHABLE TECHNOLOGY NO.	0			0		
MUST RUN / SPINNING RESERVE						
DISPATCH MODIFIER (RS/MWH)	.00			.00		
TRAJECTORY FOR DISPATCH MODIF	0			0		

```
EGEAS     EDIT   VER 02   LEV 02               CONTROL REPORT
************************************************************************************

MODE OF OPERATION                  1  -  CREATE

DATA BASE LOAD FORMAT              2  -  SUB-PERIOD

ORTHOGONALIZED LOAD FILE           1  -  PROVIDED

REPORT FILE OPTION                 0  -  STANDARD

REPORT OPTIONS
--------------
      CONTROL                      1  -  GENERATE
      MIRROR IMAGE                 0  -  NONE
      ERROR                        1  -  FATAL ONLY
      DATA BASE CONTENTS           1  -  GENERATE

INPUT FILES   NAME       VERSION   UPDATE    DATE       TIME       DESCRIP
-----------   --------   -------   ------   ---------  ---------  -------

ORTHOGONALIZED LOAD FILE
+                                  WESTERN       1          0
---HOURLY LOADS
---HOURLY GENERATION 1


OUTPUT FILE                        NAME      VERSION   UPDATE     DATE
-----------                        --------  -------   ------   --------

EGEAS DATA BASE
+                                  WESTERN       1          0


------------------------------------------------------------------------------------
EGEAS     EDIT  VER 02   LEV 02    DIAGNOSTIC SUMMARY
************************************************************************************

           *******************************************************
           **                                                   **
           **                                                   **
           **               DIAGNOSTIC SUMMARY                  **
           **                                                   **
           **                                                   **
           **          TERMINAL ERRORS               0          **
           **          FATAL ERRORS                  0          **
           **          WARNING MESSAGES             76          **
           **          DEFAULTS                    101          **
           **                                                   **
           **                                                   **
           **      HIGHEST ERROR LEVEL FOUND IS WARNING         **
           **                                                   **
           **                                                   **
           **      DATA BASE HAS BEEN SUCCESSFULLY CREATED      **
           **                                                   **
           **                                                   **
           *******************************************************
           *******************************************************
```

IDY PERIOD

FIRST YEAR . . . 2000

LAST YEAR . . . 2000

SELECTED CAPACITY PLANNING ALTERNATIVES

DEX	PLANNING ALTERNATIVE	NAME	CAPACITY MW
1	1	PH-500	500.0
2	4	L1-210	210.0
3	6	GA-108	108.0
4	7	GA-100	100.0
5	42	TIDAL	50.0

SYSTEM RELIABILITY CONSTRAINTS

TA SET F. NO.	FIRST YEAR CONSTRAINTS USED	...RESERVE MARGIN... MINIMUM PERCENT	MAXIMUM PERCENT
1	1995	.00	100.00

EXPECTED LOSS OF LOAD HOURS/YEAR	EXPECTED UNMET ENERGY PERCENT	SPINNING RESERVE OPT	REQUIREMENT
560.00	10.00	0	

ECTRIC POWER RESEARCH INSTITUTE INDIA WESTERN REGION - DYN

AS CANAL VER 02 LEV 02 STUDY PARAMETER REPORT

LTERNATIVE LIMITATION - TUNNEL CONSTRAINTS

LANNING ALTERNATIVE . . . PA 1 PA 4 PA 6 PA 7

ATA SET F. NO.	YEAR	PA 1 MIN.	PA 1 MAX.	PA 4 MIN.	PA 4 MAX.	PA 6 MIN.	PA 6 MAX.	PA 7 MIN.	PA 7 MAX
		........LIMITATIONS ON CUMULATIVE NUMBER OF UNITS							
1	2000	6.00	6.00	9.00	9.00	4.00	4.00	12.00	12.

RESERVE CONSTRAINT	1 - YES
RELIABILITY CONSTRAINT	0 - NO
LOAD DURATION CURVE	1 - CUMULANTS
SUB-PERIOD ANALYSIS	0 - NO
MAINTENANCE SCHEDULING	0 - NO
NON-DISPATCHABLE TECHNOLOGIES	1 - YES
LOADING BLOCK ANALYSIS	0 - NO
BACKWARD DYNAMIC PROGRAMMING	0 - NO
MAXIMUM SUPERFLUOUS UNITS	2
YEARS TO IGNORE TRIVIAL VARIATIONS	0
MAXIMUM STATES PER YEAR	
ANALYZED	200
RETAINED	200
REDUCING NUMBER OF STATES	
SUPERFLUOUS UNITS	0 - NO
TUNNELLING	0 - NO
RUN OPTION	1 - FULL PLANS
LOG OUTPUT OPTION	3 - ALL STATES
PLAN OUTPUT OPTION	1 - YES
SUB-PERIOD OUTPUT	0 - NO
UNIT OUTPUT	1 - YES
ENVIRONMENTAL OUTPUT	1 - YES
NUMBER OF PLANS OUTPUT	1
RESTART OPTION	0 - NO

SYSTEM RELIABILITY CONSTRAINT

DATA SET REF. NO.	FIRST YEAR CONSTRAINTS USED	...RESERVE MARGIN... MINIMUM PERCENT	MAXIMUM PERCENT	EXPECTED LOSS OF LOAD HOURS/YEAR
1	1988	.00	100.00	500.00

ALTERNATIVE LIMITATION - TUNNEL CONS

PLANNING ALTERNATIVE . . . PA 1 PA 4 PA 6

DATA SET REF. NO.	YEAR	PA 1 MIN.	PA 1 MAX.	PA 4 MIN.	PA 4 MAX.	PA 6 MIN.	PA 6 MAX.	MIN.
1	2000	7.00	8.00	8.00	9.00	3.00	4.00	11.0

(........LIMITATIONS ON CUMULATIVE NUMBER OF UN)

STUDY PERIOD YEAR 1 - 2000

PEAK 29036. MW — MIN. CAPACITY NEEDED 29036. MW — RATED C/E CAPACITY 33735.4 MW
ENERGY 163179. GWH — MAX. CAPACITY NEEDED 58072. MW — RESERVE C/E CAPACITY 33735.4 MW

STATE	CUMULATIVE UNITS					EXTRA UNITS	RESERVE PERCENT	LOLP	BACK PTR	UNSERVED ENERGY PCT	PROD COST	COMMITTED COST	REJECTED
1	7	8	3	11	18	0	42.03	.0576	0	.56[illegible]	[illegible]575.	145372.	
2	8	8	3	11	18	1	43.75	.0513	.0	.472	9[illegible]543.	146041.	
3	7	9	3	11	18	1	42.75	.0546	0	.5250	9[illegible]642.	145341.	
4	8	9	3	11	18	2	44.47	.0484	0	.4370	95679.	147039.	
5	7	8	4	11	18	1	42.40	.0559	0	.5425	94635.	145573.	
6	8	8	4	11	18	2	44.12	.0498	0	.4523	95623.	146352.	
7	7	9	4	11	18	2	43.12	.0534	0	.5027	95412.	145551.	
	8	9	4	11	18	-1	.00	.0000	0	.0000	0.	0.	(1)
8	7	8	3	12	18	1	42.37	.0561	0	.5442	94653.	145650.	
9	8	8	3	12	18	2	44.09	.0499	0	.4538	95633.	146338.	
10	7	9	3	12	18	2	43.10	.0535	0	.5043	95423.	146525.	
	8	9	3	12	18	-1	.00	.0000	0	.0000	0.	0.	(1)
11	7	8	4	12	18	2	42.74	.0546	0	.5213	93420.	14595[illegible].	
	8	8	4	12	18	-1	.00	.0000	0	.0000	0.	0.	(1)
	7	9	4	12	18	-1	.00	.0000	0	.0000	0.	0.	(1)

PRODUCTION COST STATISTICS FOR CURRENT YEAR

NUMBER OF PRODUCTION COST RUNS	22
NUMBER OF CONVOLUTIONS	191130
NUMBER OF DECONVOLUTIONS	4143
NUMBER OF AREA CALCULATIONS	141526

```
SUMMARY OF STATES GENERATED

     NUMBER OF STATES GENERATED          15

     NUMBER OF STATES REJECTED FOR
        (1) SUPERFLUOUS UNITS             4
        (2) MINIMUM RESERVE               0
        (3) MAXIMUM RESERVE               0
        (4) LOSS OF LOAD PROBABILITY      0
        (5) NO PATHWAY                    0
        (6) UNSERVED ENERGY               0

     NUMBER OF FEASIBLE STATES           11

     NUMBER OF STATES RETAINED           11

PLAN SORTING AND SELECTION

     UNIQUE PLANS GENERATED      11
     PLANS TO BE OUTPUT           1
```

ELECTRIC POWER RESEARCH INSTITUTE — INDIA WESTERN REGION - DYNAMIC

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EXPANSION PLAN 1

YEAR	NEW UNITS ADDED	RESERVE MARGIN	LOLP	UNSERVED ENERGY PCT	PROD	CAPITAL	FIX O+M	ANNUAL	CUM ANN	PRES ...
2000	7 8 3 11 18	42.03	.0576	.5665	41273.	17917.	2428.	61618.	61618.	[illegible]
EXT.		42.03	.0576	.5665	88281.	36081.	5194.			[illegible]

(Columns PROD through PRES are under the heading: COST SUMMARY)

DYNAMIC PROGRAM - COMPLETED SUCCESSFULLY

ELECTRIC POWER RESEARCH INSTITUTE — INDIA WESTERN REGION - DYNAMIC

EGEAS CANAL VER 02 LEV 02 — INDEX OF REPORTS

CONTROL REPORT PAGE 1

MIRROR IMAGE REPORT PAGE

ELECTRIC POWER RESEARCH INSTITUTE   TEST RUN - R5   9/16/82   09 20 00

[illegible]   PRODUCTION COST - ANNUAL BY FUEL CLASS REPORT   PAGE 9

YEAR 1

YEAR	TOTAL SYSTEM ENERGY GWH	TOTAL SYSTEM COST M$	FUEL CLASS - NUCL ENERGY GWH	FUEL CLASS - NUCL COST, M$	FUEL CLASS - COAL ENERGY, GWH	FUEL CLASS - COAL COST M$	FUEL CLASS - OIL ENERGY, GWH	FUEL CLASS - OIL COST, M$
1988	[illegible]	1578	20748	323	20906	566	8012	641
1989	[illegible]	1855	21311	358	21433	622	9645	820
1990	[illegible]	1818	27181	492	20187	638	7816	713
1991	[illegible]	2117	27714	541	21001	702	9079	889
1992	[illegible]	2297	33615	702	20191	722	8125	858
EXT	[illegible]	1991	33615	1501	20191	1506	8125	1949

YEAR	FUEL CLASS - CT ENERGY GWH	FUEL CLASS - CT COST, M$	FUEL CLASS - HYDR ENERGY GWH	FUEL CLASS - HYDR COST, M$	FUEL CLASS - STOR ENERGY GWH	FUEL CLASS - STOR COST, M$	FUEL CLASS - SOL ENERGY GWH	FUEL CLASS - SOL COST, M$
[illegible]	111	19	430	0	250	0	0	0
[illegible]	116	51	430	0	250	0	0	0
[illegible]	17	6	430	0	250	0	0	0
1991	109	16	430	0	250	0	0	0
1992	100	15	430	0	250	0	0	0
EXT	[illegible]	35	430	0	250	0		

NOTE: ANNUAL COSTS ARE IN MILLIONS OF CURRENT DOLLARS
EXTENSION PERIOD COSTS ARE IN MILLIONS OF DOLLARS DISCOUNTED TO THE BEGINNING OF 1980

Figure 9-8. Production Cost Fuel Class Report

UNIT NAME	ALT INST YEAR	CODE	RATED CAPACITY MW	AVERAGE HEAT RATE KCAL/KWH	FUEL COST RS/MKCAL	CAPACITY FACTOR PERCENT	GENERATION GWH	FUEL [illegible]	VARIABLE O&M [illegible]
TIDAL	2000	NOT	50.0	0.	.0000	18.75	[illegible]	[illegible]	2047.
TIDAL	2000	NOT	50.0	0.	.0000	18.75	81.9	0.	2047.
TIDAL	2000	NOT	50.0	0.	.0000	18.75	81.9	0.	2047.
TIDAL	2000	NOT	50.0	0.	.0000	18.75	81.9	0.	2047.
TIDAL	2000	NOT	50.0	0.	.0000	18.75	[illegible]	0.	2047.
TIDAL	2000	NOT	50.0	0.	.0000	18.75	81.9	0.	2047
TIDAL	2000	NOT	50.0	0.	.0000	18.75	[illegible]	0.	2047.
TIDAL	2000	NOT	50.0	0.	.0000	18.75	[illegible]	0.	2047.
TIDAL	2000	NOT	50.0	0.	.0000	18.75	[illegible]	0.	[illegible]
TIDAL	2000	NOT	50.0	0.	.0000	18.75	[illegible]	0.	[illegible]
TIDAL	2000	NOT	50.0	0.	.0000	18.75	81.9	[illegible]	[illegible]
TIDAL	2000	NOT	50.0	0.	.0000	18.75	[illegible]	[illegible]	[illegible]
TIDAL	2000	NOT	50.0	0.	.0000	18.75	81.9	0.	[illegible]
TIDAL	2000	NOT	50.0	0.	.0000	18.75	[illegible]	[illegible]	[illegible]
TIDAL	2000	NOT	50.0	0.	.0000	18.75	81.9	[illegible]	2047.
TIDAL	2000	NOT	50.0	0.	.0000	18.75	81.9	0.	[illegible]
TIDAL	2000	NOT	50.0	0.	.0000	18.75	[illegible]	[illegible]	2047.
TIDAL	2000	NOT	50.0	0.	.0000	18.75	[illegible]	[illegible]	[illegible]
BANSAGAR-5,6,7,8		HYDR	[illegible]	0.	.0000	87.50	[illegible]	[illegible]	[illegible]
KUTCH LIGNITE-1			70.0	2907.	33.3300	47.02	[illegible]	[illegible]	[illegible]
KUTCH LIGNITE-2			70.0	2907.	33.3300	47.02	[illegible]	[illegible]	[illegible]
KUTCH LIG, EXTN			70.0	2907.	33.3300	47.02	[illegible]	[illegible]	[illegible]
[illegible]			500.0	2565.	60.7900	47.47	[illegible]	[illegible]	[illegible]
[illegible]			500.0	2564.	60.7900	47.67	[illegible]	[illegible]	[illegible]
[illegible]			235.0	2664.	60.7900	67.67	[illegible]	[illegible]	[illegible]
KAKRAPAR-2			235.0	2664.	60.7900	67.67	[illegible]	[illegible]	[illegible]
KAKRAPAR-3			235.0	2664.	60.7900	67.67	1393.0	[illegible]	[illegible]
KAKRAPAR-4			235.0	2664.	60.7900	67.67	1393.3	[illegible]	[illegible]
PH-500	2000		500.0	2701.	60.0000	56.13	2451.7	[illegible]	[illegible]
PH-500	2000		500.0	2701.	60.0000	56.13	2451.7	[illegible]	[illegible]
GA-100	2000		100.0	2300.	258.6000	57.99	547.1	[illegible]	0.
GA-100	2000		100.0	2300.	258.6000	57.78	[illegible]	[illegible]	0.
BARGI		HYDR	45.0	0.	.0000	65.14	260.0	0.	6500.
WANAKBORI EX-2			210.0	2664.	214.0000	41.27	757.1	[illegible]	19927.
WANAKBORI EX-3			210.0	2664.	214.0000	40.31	739.4	[illegible]	[illegible]
GANDHI NGR EX-1			210.0	2664.	214.0000	39.51	724.9	[illegible]	19119
PARLI 5			210.0	2664.	214.0000	38.74	710.6	[illegible]	177[illegible]
GANDHI NAGAR-EX-			210.0	2664.	214.0000	37.90	[illegible]	[illegible]	[illegible]
BANSAGAR-1		HYDR	105.0	0.	.0000	51.50	473.3	0.	[illegible]
BANSAGAR-2		HYDR	105.0	0.	.0000	51.4	473.3	0.	[illegible]
[illegible]		HYDR	8.0	0.	.0000	21.45	[illegible]	0.	[illegible]
DHIRA T.P.		HYDR	40.0	0.	.0000	10.02	35.0	0.	[illegible]
KADANA-1		HYDR	60.0	0.	.0000	9.73	51.0	0.	1275
KADANA-2		HYDR	60.0	0.	.0000	9.73	51.0	0.	1275.
KADANA-3		HYDR	60.0	0.	.0000	9.73	51.0	0.	1275.
KADANA-4		HYDR	60.0	0.	.0000	9.73	51.0	0.	1275.
[illegible]	2000		210.0	2804.	214.0000	35.70	[illegible]	[illegible]	[illegible]
[illegible]	2000		210.0	2804.	214.0000	5.50	100.9	[illegible]	[illegible]
[illegible]	2000		210.0	2804.	214.0000	5.25	[illegible]	[illegible]	[illegible]
[illegible]	2000		210.0	2804.	214.0000	5.09	93.3	55995.	[illegible]
[illegible]	2000		210.0	2804.	214.0000	4.90	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]		210.0	2804.	214.0000	4.67	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]		210.0	2804.	214.0000	4.51	[illegible]	[illegible]	[illegible]
DHUVARAN GAS-1			27.0	2907.	214.0000	.01	.0	[illegible]	[illegible]
DHUVARAN GAS-2			27.0	2907.	214.0000	.01	.0	[illegible]	[illegible]
DHUVARAN-[illegible]			140.0	2907.	214.0000	3.57	44.8	[illegible]	[illegible]
[illegible]			140.0	2907.	214.0000	3.35	[illegible]	[illegible]	[illegible]
[illegible]			140.0	2907.	[illegible]	2.99	34.6	[illegible]	[illegible]
[illegible]			140.0	2907.	214.0001	2.93	35.8	[illegible]	[illegible]
GANDHI NAGAR-1			120.0	2907.	214.0000	3.35	35.2	21571.	131[illegible]
GANDHI NAGAR-2			120.0	2907.	214.0000	3.29	34.4	[illegible]	1281.
SABARMATI-1			110.0	2907.	214.0001	3.22	31.0	[illegible]	[illegible]
AJANTA P.S.S		HYDR	100.0	0.	.0000	5.84	51.0	0.	1275.
SABARMATI-2			110.0	2907.	214.0000	3.04	29.3	18197.	1097.
DHUVARAN-3			63.5	2907.	214.0000	3.00	16.7	[illegible]	[illegible]
DHUVARAN-4			63.5	2907.	214.0000	2.97	[illegible]	[illegible]	617.
PARAS-2			62.5	2907.	214.0000	2.74	15.0	9305.	561.
PARLI-1			30.0	2907.	214.0000	2.32	7.4	4593.	277.
PARLI-2			30.0	2907.	214.0000	2.81	7.4	4575.	274.
SABARMATI			110.0	2907.	214.0001	2.85	27.3	17011.	[illegible]
URAN GAS-1			60.0	2907.	258.6000	3.83	20.1	[illegible]	0.
URAN GAS-2			60.0	2907.	258.6000	3.77	19.8	14871.	0.
URAN GAS-3			60.0	2907.	258.5999	3.65	19.1	14375.	0.
URAN GAS-4			60.0	2907.	258.6000	3.64	19.1	14329.	0.

PLAN 1 LAST OUTPUT

YEAR	PEAK LOAD,MW	ENERGY GWH	...RATED CAPACITY, MW.... INSTALLED	RETIRED	TOTAL	RESERVE CAPACITY	RESERVE PERCENT	LOSS OF LOAD PROBABILITY	.......NEW UNITS....... CAPACITY,MW	CAPITAL CO
2000	23036.	163179.	10502.	217.	42037.	42037.	44.78	.0466	8302.	136339.

YEAR	..ALL UNITS.. PROD. COST	.......NEW UNITS ONLY....... FIXED O & M	FIXED CHARGES	......................COST SUMMARY...................... ANNUAL	CUM. ANNUAL	PRESENT WORTH	CUM. PRES. WOR
2000	39669.	2771.	18454.	60894.	60994.	15630.	15630.
EXT.						127720.	143350.

NOTES - ANNUAL COSTS ARE IN MILLIONS OF CURRENT RUPEES.
- PRESENT WORTH COSTS ARE IN MILLIONS OF RUPEES DISCOUNTED TO THE BEGINNING OF 1988.

1ELECTRIC POWER RESEARCH INSTITUTE WESTERN REGION - DYNAM

EGEAS REPORT VER 02 LEV 02 PRODUCTION COST - SYSTEM ANNUAL REPORT PAGE

PLAN 1 SYSTEM A, INDEPENDENT DISPATC

YEAR	....................ENERGY, GWH.................... GENERATION	DUMP	CHARGING	PURCHASE	UNMET	TOTAL	...............COST, MRS............... FUEL	VAR O+M	PURCHASE	UNMET	TOTAL
2000											
+	162527.	0.	-22.	0.	675.	163179.	35434.	2885.	0.	1350.	39669.
EXT.											
+	162527.	0.	-22.	0.	675.	163179.	75792.	6170.	0.	2887.	84849.

NOTES - GENERATION INCLUDES CHARGING OF STORAGE UNITS (IF ANY).
- ANNUAL COSTS ARE IN MILLIONS OF CURRENT RUPEES.
- EXTENSION PERIOD COSTS ARE IN MILLIONS OF RUPEES DISCOUNTED TO THE BEGINNING OF 1988.

1ELECTRIC POWER RESEARCH INSTITUTE WESTERN REGION - DYNAM

EGEAS REPORT VER 02 LEV 02 PRODUCTION COST - ANNUAL BY FUEL CLASS REPORT PAGE

PLAN 1

YEAR	......TOTAL SYSTEM..... ENERGY, GWH	COST,MRS	...FUEL CLASS - COAL... ENERGY, GWH	COST,MRS	...FUEL CLASS - NUCL... ENERGY, GWH	COST,MRS	...FUEL CLASS - GAS ... ENERGY, GWH	COST,MRS
2000	162527.	38319.	108975.	26046.	13400.	2193.	13218.	9447.
EXT.	162527.	81963.	108975.	55711.	13400.	4670.	13218.	20207.

YEAR	...FUEL CLASS - LIGN... ENERGY, GWH	COST,MRS	...FUEL CLASS - HYDR... ENERGY, GWH	COST,MRS	...FUEL CLASS - STOR... ENERGY, GWH	COST,MRS
2000	863.	116.	20714.	518.	357.	9.
EXT.	963.	248.	20714.	1108.	357.	19.

NOTES - ANNUAL COSTS ARE IN MILLIONS OF CURRENT RUPEES.
- EXTENSION PERIOD COSTS ARE IN MILLIONS OF RUPEES DISCOUNTED TO THE BEGINNING OF 1988.

1ELECTRIC POWER RESEARCH INSTITUTE WESTERN REGION - DYNAM

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YEAR   SUB WEEK 1

UNIT NAME	YEAR IN-SERVICE	CAPACITY MW	AVERAGE HEAT RATE BTU/KWH	FUEL COST $/MBTU	CAPACITY FACTOR PERCENT	GENERATION GWH	FUEL K$	VARIABLE O & M K$	PRODUCTION COST K$	PRODUCTION COST $/MWH
NUKE 1		1200 0	10100	1 3255	73 64	965 0	12919	2120	15039	15 58
NUKE 2		1200 0	10100	1 3255	73 64	965 0	12919	2120	15039	15 58
COAL 1		600 0	9800	2 2293	74 75	489 8	10700	2242	12942	26 43
COAL 2		600 0	9800	2 2293	74 75	489 8	10700	2242	12942	26 43
COAL 3		400 0	9910	2 2293	79 18	345 8	7641	1583	9224	26 67
COAL 4		400 0	9910	2 2293	79 18	345 8	7641	1583	9224	26 67
COAL 5		0 0	0	0 0	0 0	0 0	0	0	0	0 0
COAL 6		200 0	10160	2 2293	86 52	189 0	4407	865	5272	27 90
COAL 7		200 0	10460	2 2293	86 25	188 4	4393	862	5255	27 90
COAL 8		200 0	10160	2 2293	85 84	187 5	4372	858	5230	27 90
COAL 9		200 0	10460	2 2293	85 14	185 9	4336	851	5187	27 90
COAL 10		200 0	10160	2 2293	84 04	183 5	4280	840	5120	27 90
COAL 11		200 0	10460	2 2293	82 48	180 1	4201	825	5025	27 90
COAL 12		200 0	10460	2 2293	80 32	175 4	4091	803	4894	27 90
OIL 1		800 0	9000	8 7634	23 86	208 5	16443	942	17385	83 39
OIL 2		400 0	9300	8 7634	15 67	68 4	5578	309	5887	86 02
OIL 3		200 0	9745	8 7634	7 19	15 7	1340	71	1411	89 92
OIL 4		200 0	9745	8 7634	5 63	12 3	1049	55	1105	89 92
OIL 5		200 0	9745	8 7634	5 24	11 4	977	52	1029	89 92
OIL 6		200 0	9745	8 7634	3 32	7 3	619	33	652	89 92
OIL 7		200 0	9745	8 7634	2 51	5 5	467	25	492	89 92
OIL 8		200 0	9745	8 7634	1 88	4 1	350	18	368	89 92
OIL 9		200 0	9745	8 7634	1 39	3 0	259	14	272	89 92
CTS1		50 0	11500	9 3705	0 33	0 2	20	1	20	112 28
CTS2		50 0	11500	9 3705	0 30	0 2	18	1	18	112 28
CTS3		50 0	11500	9 3705	0 28	0 2	16	1	17	112 28
CTS4		50 0	11500	9 3705	0 25	0 1	15	1	16	112 28
CTS5		50 0	11500	9 3705	0 23	0 1	14	1	14	112 28
CTS6		50 0	11500	9 3705	0 21	0 1	13	1	13	112 28
CTS7		50 0	11500	9 3705	0 19	0 1	11	0	12	112 28
CTS8		50 0	11500	9 3705	0 18	0 1	10	0	11	112 28
CTS9		50 0	11500	9 3705	0 16	0 1	9	0	10	112 28
CTS10		50 0	11500	9 3705	0 14	0 1	9	0	9	112 28
CTS11		50 0	11500	9 3705	0 13	0 1	8	0	8	112 28
CTS12		50 0	11500	9 3705	0 12	0 1	7	0	7	112 28
CTS13		50 0	11500	9 3705	0 11	0 1	6	0	7	112 28
CTS14		50 0	11500	9 3705	0 10	0 1	6	0	6	112 28
CTS15		50 0	11500	9 3705	0 09	0 0	5	0	5	112 28
CTS16		50 0	11500	9 3705	0 08	0 0	5	0	5	112 28
CTS17		50 0	11500	9 3705	0 07	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

ELECTRICITY PRICING IN THEORY AND PRACTICE

- S.Ramesh

1. PUBLIC UTILITIES AND PRICING

Public utilities such as electricity systems, transport networks, etc.provide basic services essential to daily life, and as such, the State has a vital stake in their pricing and distribution. They are also "natural monopolies", in so far as the nature of service provided by them is such that, over considerable geographical areas, they can function properly only under conditions of monopoly. This is because large "indivisibilities" (also called "lumpiness" by several writers) characterise investments in these industries. For example, if there are two electricity supply systems operating within the same geographical area, the resulting over-investment and waste owing to criss-crossing of distribution lines etc. can readily be imagined. The nature and characteristics of public utilities have, therefore, inevitable implications for pricing from the fiscal and welfare view-points, which are often in conflict with one another.

2. NATURE AND CHARACTERISTICS OF ELECTRIC UTILITIES

Apart from being a natural monopoly, the electricity supply industry has specific economic characteristics of its own, both on the supply and demand sides, which have implications for pricing in electricity undertakings. On the supply side, there are

different types of capacity producing electricity and they work as part of an integrated system. The costs of supply vary by voltage and by time of supply. There are also uncertainties on the supply side such as, for example, variable generation in hydro plants depending upon water inflows, etc., and unpredictable break-downs (known as 'forced outages' in the industry) mainly of thermal power plants. Apart from this uncertainty of supply, a major economic characteristic of electricity is its <u>non-storability</u>.

On the demand side also, there are some important features which must be noted. The demand is variable by time of day, season, etc. and this variability, combined with the non-storability on the supply side, has major economic implications which we shall be examining presently.

This monopolistic nature of electric utilities enables them to practise price descrimination in suitable cases. The conditions necessary to practise differential pricing are: (1) Monopoly/near monopoly on the supply side; (2) A total demand that can be further sub-divided into separate markets, each with a different price elasticity of demand*; and (3) Some means of insulation of each market from the others, so that those

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* The price elasticity of demand is defined as the ratio of the percentage change in quantity demanded to a 1% change in price, and measures the responsiveness of quantity demanded to changes in price.

who buy at the lower price cannot resell to those who would have to pay higher prices.* It is clear that all these conditions are fulfilled in electric utilities which can, therefore, practise differential pricing. Differential pricing enables the utility to balance fiscal objectives with welfare objectives, which are conflicting to a certain extent; more important, it enables the utility to adjust its prices for different consumers or consumer-groups, in order to recover the differential costs imposed on the utility by them.

3. OBJECTIVES OF SOUND PRICING SYSTEM

There are three main objectives of a sound pricing structure which can be generally stated as:

(a) A fair return and adequate revenues;

(b) A fair distribution of costs among consumers; and

(c) rates that discourage waste and promote all justified uses of utility services, and ensure efficient allocation of resources**.

The concern for "fairness" in the rate of return arises from the possibility of misuse of the monopoly power of electric undertakings. The criteria of fairness obviously would depend on several considerations,

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* George J Stigler, The Theory of Price, Macmillan, New York, page 223.

** Bonright, James C, Principles of Public Utility Rates, cited in Carfield & Lovejoy, Public Utility Economics, New York 1964.

including the magnitude and behaviour of national economic variables. Fairness in distribution of costs among different consumers, results from the genuine concern that, as far as possible, the buyer should pay the cost of the services provided. The third objective is perhaps the most important, as it concerns efficient allocation of resources, which is particularly important in developing countries.

4. TECHNICAL PROBLEMS OF ELECTRICITY PRICING

The technical problems in this area, are those of tariff making which are: (a) complexity due to the mass of technical detail, which must be considered in designing/administering rate schedules; (b) "ignorance" of rate-makers of demand and supply functions; and (c) the need to consider numerous conflicting standards of fairness and functional efficiency.* These technical problems play a very important role in the study of electricity pricing. An electricity supply system is a complex network of different kinds of generating capacity, a transmission network to transmit electricity from the generating centres to the load centres, and a distribution network which provides supply to the ultimate points of consumption. The tariff-makers generally do not have adequate information, especially on the demand side; ideally, the elasticities of demand

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* Bonbright, op. cit. page 292.

of different categories of consumers should be known for an efficient tariff exercise, but generally this information is not adequate, and the tariff-makers have to make use of available estimates.

5. APPROACHES TO ELECTRICITY PRICING

Pricing policies in the electricity industry, even in developed countries, have historically been dominated by professional utility managers and engineers. The traditional approach is basically an accounting approach.* This approach is based on a calculation of historical costs as derived from the accounts of the utility. Obviously this involves a comprehensive stock-taking of all assets, old and new. Using this stock-taking, certain "capacity related" costs are derived and various "energy related" costs are evaluated. Maintenance costs are allocated to the former or the latter as considered necessary. Purely "customer related" costs are allocated as equitably as possible among customers on the basis of who has imposed costs on the utility. A tariff structure is formulated for each customer class, which includes KW charges as well as KWHr charges.

The basic principles underlying the above approach, which still governs rate-making all over the

* The word "accounting" is used in electricity economics, in the sense "as based on the financial accounts".

world, is that accounting or historical costs, should form the basis of pricing*.

Economists are now generally agreed that the accounting approach is inadequate for efficient resource allocation. The economic argument goes as follows. Accountants are concerned with the recovery of historical or sunk costs, whereas resource allocation emphasises the actual resources saved or used by every consumer decision. According to this argument, "bygones are bygones" and historical costs have no relevance to decisions which are made *today*, which involve resources in the present or in the future.

Prices based on historical or accounting costs,are also inadequate as *signalling* device. Prices should be 'signals' to consumers to increase or curtail their consumption and need to be related to the incremental costs of meeting that consumption. The economist's argument would be that prices should reflect these incremental (or marginal) costs and thus provide the correct signals for the consumption changes. In the words of Turvey and Anderson, "the backward looking estimate of the traditional approach, creates an illusion that resources...................... are as cheap or as expensive as in the past. On the one hand, this may cause over-investment and unnecessary scarcity.

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* See Turvey R. & Anderson D, 'Electricity Economics', Johns Hopkins University Press, 1977, Chapter 2.

In addition, if the past holds a number of poor projects, the sunk costs of mistakes, if reflected in prices, will overstate the costs to the consumer of extra consumption, which is not efficient .... for efficient resource allocation, prices should be related to the resource costs of changes in consumption; i.e. pricing according to marginal, not average, cost. The change in the cost to a consumer of altering his electrical behaviour will then mirror the change in the cost to the enterprise".*

In being inadequate as a signalling device, the accounting approach ignores the incentive effects of tariffs. Tariffs give incentives to consumers by telling them when electricity is cheap, e.g. during off-peak hours, and when it is expensive, e.g.during peak hours. Incentive effects are obviously relevant in regulating electricity demand in accordance with the requirements of the undertaking, which incurs different costs during different periods of the daily cycle. The average accounting costs, being unrelated to the incremental cost of supply in different periods, are thus inadequate in this respect. We shall return to this point later in this paper.

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* Turvey and Anderson, 'Electricity Economics', op.cit

6. THE GENERAL CASE FOR MARGINAL COST PRICING IN ELECTRIC UTILITIES:

Marginal cost pricing has a long history in economic literature starting with the famous article by Hotelling in 1938, which itself was an elaboration and a modification of an earlier contribution by a French engineer, Dupuit.*

In the earlier literature, considerable emphasis was given by economists to the problems of a deficit arising out of marginal cost pricing in public utilities subject to decreasing costs. This earlier literature concentrated on the "excess capacity" case, where unit costs were decreasing over the relevant range of the cost curve, as a result of indivisibilities. The various alternative means of meeting the deficit, and their welfare implications, were considered in detail in this literature.**

The emphasis of the earlier literature on the problems arising from decreasing costs, has now given way to the problems of pricing in an expanding electric utility industry.

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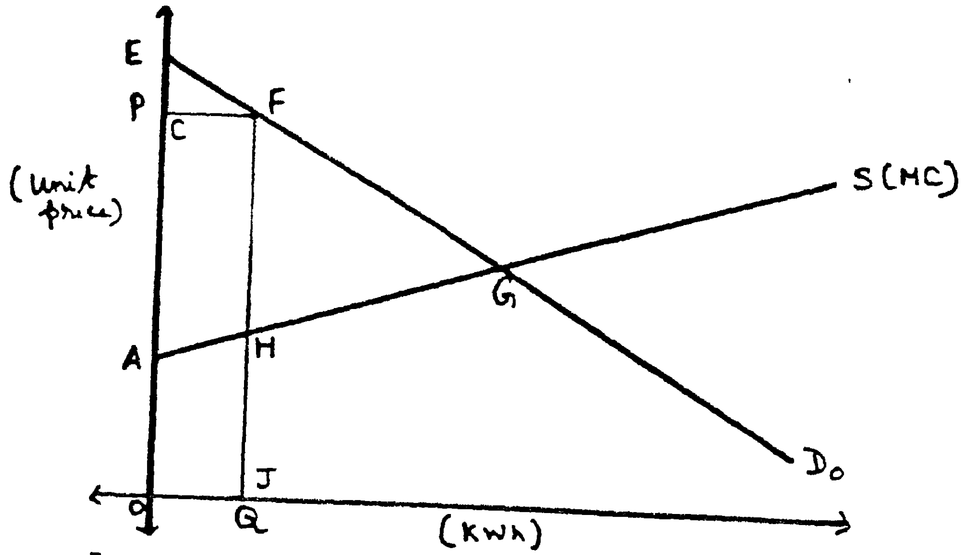
* Hotelling H, "The General Welfare in relation to Problems of Taxation and of Railway and Utility Rates", Econometrica, Vol. 6, 1938.

** For detailed references, see Nancy Ruggles, "Recent Developments in the Theory of Marginal Cost Pricing", reprinted in Turvey (Ed.), Public Enterprises, Penguin Books, London, 1968.

The theoretical rationale for setting prices equal to marginal cost in an electric utility has been well explained by many writers. The following diagram, adapted from Munasinghe and Warford, explains the basic marginal cost theory*.



In the above diagram, $EFGD_o$ is the demand curve (which gives the KWH demanded per year on the horizontal axis and the average price on the vertical axis), while AGS is the supply curve showing the marginal cost of supplying additional units of output. At price p and demand Q, the total benefit derived from consumption of electricity is represented by the consumers' willingness to pay, i.e., the area under the demand curve, OEFJ. The cost of supplying any quantity of electricity is given by the area under the supply curve, i.e., OAHJ. The total benefit minus total supply cost is, therefore, the net benefit derived from the consumption of

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* Munasinghe and Warford, "Electricity Pricing, Theory and Case Studies", Johns Hopkins University Press, Baltimore, 1982.

electricity, i.e. the area AEFH. The objective is to maximise the net benefit, and this is clearly achieved at the point G (price p_0, quantity Q_0. In mathematical terms, the net benefit is given by:

$$NB = \int_0^Q p(q)dq - \int_0^Q MC(q)dq$$

where p(Q) and MC(Q) are equations representing the demand and supply curves respectively. Maximising NB:

$$\frac{d(NB)}{d(Q)} = 0, \text{ i.e. } p(Q) - MC(Q) = 0; \ p(Q) = MC(Q)$$

showing the point of intersection of the demand and marginal cost curves (price p_0, quantity demanded and supplied, Q_0).

In actual practice, of course, adequate information regarding the demand curve may not be available, though the marginal cost curve may be estimated more accurately. Therefore, the establishment of the equilibrium point, or market clearing price, will be an iterative process. However, the conceptual basis for setting price equal to the marginal cost, and increasing the supply of electricity until the market clears, remains valid.

From the point of view of society in general, it can be stated that the purpose of pricing should be to allocate national resources efficiently by providing

appropriate signals to consumers. Prices act as signals to consumers who see them as costs of using the commodity, which in this case is electricity. If the price of electricity is fixed below its marginal cost of production, consumers will think (and act accordingly), that the cost of an additional unit of electricity is less than the cost to society. In this case, more resources would be devoted to electricity production than is socially efficient.*

It may be objected that, while the above logic is valid for new consumers, what is the justification for charging marginal costs to existing consumers? Here it must be explained that <u>all</u> consumption is new in the economic sense. Just as B, a new group of consumers, may impose on the electric utility the need to add to system capacity because of their (new) additional requirements of electricity, so can an existing group A impose this need on the utility by <u>continuing</u> their consumption; after all, group A can save additional costs to the utility by reducing their purchases. As Kahn points out, A's continuing to take service is just as responsible, in proportion to the amount they take, for

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* This argument presupposes the absence of "externalities", such as pollution costs, etc., and also that all costs are measured in terms of <u>social</u> costs. Strictly speaking, marginal costs are marginal <u>social</u> costs, and the marginal costs as calculated in actual practice, are only approximations to the marginal social costs.

the need to expand investment, as B's increasing needs. Even though B's demand is marginal in a temporal sense, both groups are marginal in the economic sense.*

Marginal cost pricing in electricity therefore involves a tariff structure so framed that the cost to any consumer of changes in the pattern/level of his consumption, equals the costs to the electricity industry as a consequence of his action. Such pricing will cause individual consumption decisions to conform to the national interest if (a) consumers are well-informed and rational, (b) the distribution of income is taken as given, (c) the cost to the industry of responding to consumption changes coincides with social costs i.e. value to the economy of the resources involved (this means absence of external economies/diseconomies), and (d) prices of substitutes/complements for electricity, are equal to their marginal (social) costs; a similar condition exists in the case of prices of goods using electricity in production**.

Though the above conditions are not met fully in any economy, Turvey concludes that there is a presumption in favour of marginal cost pricing for the

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* See A.E. Kahn, "The Economics of Regulation", Wiley, New York, 1970, Vol.I, page 140.

** See Turvey R.,"Optimal Pricing and Electricity Supply", The MIT Press, Cambridge, 1968, for a fuller discussion of these points.

following reasons: Firstly, consumers' rationality is not an unrealistic assumption. Secondly, the electricity industry should not try to set right (by tariff policy) the distribution of income in any manner, as that is a more appropriate field for fiscal policy; in that sense, it should act as if the distribution of income is acceptable. Thirdly, as all other prices are not equal to marginal cost, and there are some external economies/diseconomies*, the problem becomes one of 'sub-optimization' i.e. second best.

The argument used sometimes against marginal cost pricing is that the rule is really an "all-or-nothing rule", in the sense that it does not help efficient resource allocation in its application to one industry unless it is applied to all others. Here it may be pointed out that interdependence between various activities is not as complete as implied in the above argument. What is relevant to marginal cost pricing is the situation regarding substitutes and complementary goods.** Where a substitute is priced lower than

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* Examples of externalities in the electricity industry, are atmospheric pollution caused by thermal stations, and environmental problems (owing to effects on flora and fauna in the area) of hydro-electric projects.

** See M.J. Farrell, 'In Defence of Public-Utility Price Theory, Oxford Economic Papers, new Series Vol.10 (1958), reprinted in Turvey (Ed) Public Enterprise, Penguin Books, 1968, for a detailed discussion of this point. Examples of substitutes are gas in developed countries, and Kerosene oil (for lighting) and diesel oil (for engines, motors etc.) in developing countries.

marginal cost, obviously marginal cost pricing for electricity cannot lead to efficient resource allocation. Resources devoted to producing electricity, will be influenced by such deviations, the more so if they concern close substitutes/complementary goods. Therefore, "......... the right policy is to pursue marginal cost pricing for electricity subject to corrections made only for those non-optimalities which are known to have a significant effect on the demand or cost structure of electricity".* Even in the case of these non-optimalities, it is suggested that it may be better to tackle them directly wherever possible, than allow for them in electricity pricing.

7. SHORT-RUN AND LONG-RUN MARGINAL COSTS

The difference between short-run marginal costs and long-run marginal costs can be stated very simply. Short-run marginal costs represent the marginal costs of supply, when capacity is given. In the long run, however, we can add to the system capacity and, therefore, the costs can be different, depending upon the mix of capacity that can be made available in the longer run. Theoretically speaking, short-run and long-run marginal costs would be equal, if output is optimal. Short and long run marginal cost pricing are in fact equivalent if correct forecasting is done, i.e. if future assumptions made in calculating long-run marginal

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* R. Turvey, Optimal Pricing etc. (1968) op. cit.

cost turn out to be valid. However, anticipations of the future demands can prove to be over-estimated or under-estimated and there can be a difference between the two marginal costs at any point of time. Boiteax has shown that, whatever the capacity of existing plant, the need to keep prices steady, makes long-term policy preferable to the instantaneous, optimal use of investment, i.e. the proper approach is fix prices equivalent to long-run marginal costs.* As short-run marginal costs can vary from time to time, frequent changes would also be implied in the pricing system. In an actual situation, distortions can arise in the short run, if prices are based on long-run marginal costs. Though it is accepted that the relevant signals to consumers should be still based on long-run marginal costs, practical problems very often result in a situation where it may not be possible to follow these rules strictly. For instance, Electricite de France, who were the first electric utility in the world to systematically introduce and refine the application of marginal cost pricing, faced this problem after the 1974 oil crisis. The experience of the EDF in meeting this crisis and the resulting implications for electricity

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* See Boiteax R. in Nelson J.R. (Ed.), "Marginal Cost Pricing in Practice, Prentice Hall, 1964.

tariffs in France have been reported in a paper by J.Pl. Roux of the EDF.* When the price of oil tripled in 1974, marginal energy costs also tripled, as oil-fired stations were at the margin. Meanwhile, the new economic conditions called for a changed long-term generation mix, and, in the new optimal investment plan, the nuclear programme accelerated significantly. In the new structure, marginal energy cost was the cost of nuclear fuel. EDF thus faced a conflict between short-term and long-term marginal costs. If they had immediately adopted long-term marginal cost pricing, as dictated by economic principles accepted by them, EDF would have faced a financial crisis in the short run. The compromise adopted by EDF, was a gradual adjustment to the LRMC over a few years, progressively narrowing the gap between the price and LRMC. This example shows the difficulties of a strict application of marginal cost pricing in a period when economic conditions are changing fast.

The long-run marginal cost is thus the correct basis for tariff policy, as such a tariff system would promote rate stability and also provide consumers with

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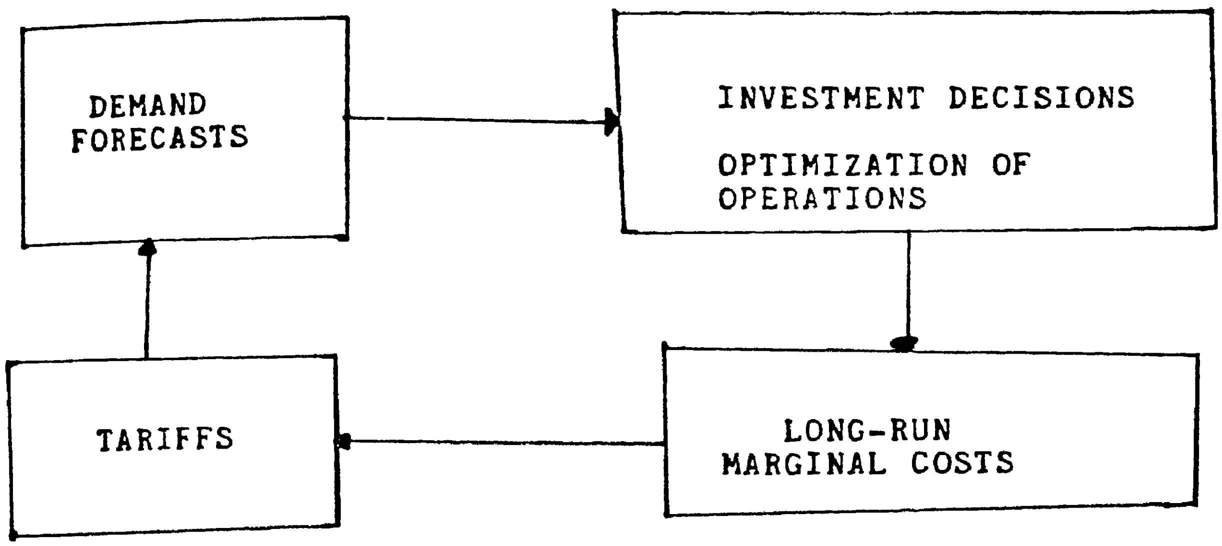
* Roux J.Pl., "Marginal Cost Pricing: Updating the French Electricity Tariffs", in 'Costing and Pricing Electricity in Developing Countries', Munasinghe and Rungta (Ed), Asian Development Bank, 1984.

good long-run signals. It has been explained earlier that tariff making is a continuous iterative process. One point that must be emphasized about long-run marginal cost is that it is <u>always</u> related to a specified (future) load increment, and, therefore, must be related to an optimal long-term investment plan. The following diagram shows how this iterative process can operate in principle.



As is clear in the above diagram, an optimal investment-cum-operation plan to meet a certain demand forecast in a future year (say 2000 AD) is prepared, and the long-run marginal costs are based on this mix. The tariffs resulting from this LRMC are again used to make revised demand forecasts which in turn result in a revised optimal investment plan which again results in a new LRMC structure and so on, until the gap is significantly narrowed. In practice, of course, a more pragmatic approach can be used where LRMC resulting from

one iteration, will be the basis for new power tariffs. The demand behaviour is observed over some time period, after which the LRMC/tariffs are re-estimated.*

LRMC, therefore, is always related to a specified load increment and there can be as many LRMCs as there are load increments. To put it more rigorously, LRMC in year N of a given load increment will be equal to the excess of the present worth of the increment of system costs resulting from a permanent load increment starting at beginning of year N, over the present worth ....year (N+1). In substance, LRMC in present worth terms is simply the present worth of all system costs to meet the specified load increment, less what they would be without that increment. It must be noted here that the increment is not only of capital costs but of system costs i.e., it would include fuel savings etc., which could arise because of the change in the mix of generating capacity, with attendant implications for operations.

8. INGREDIENTS OF LONG-RUN MARGINAL COSTS

The ingredients of long-run marginal costs in an electricity system (in relation of course, to the specified load increment for the specified future year)

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* See Munasinghe and Rungta for a useful discussion on this point, "Power Tariffs - An Overview", in 'Costing and Pricing Electricity in Developing Countries', Op. Cit., 1984.

are:

(a) Generation capacity costs.

(b) Transmission and Distribution Capacity Costs -- at each voltage level, including transformer costs.

(c) Energy (or running) costs and losses - at each voltage level.

(d) Customer or connection costs.

9. PRINCIPLES OF PEAK LOAD PRICING

Peak load Pricing in electricity, is a recognition of one important characteristic of electricity, namely, that demand varies according to the time of the day/ season, but the supply is non-storable. The marginal costs of supply, therefore, vary according to the time/period of supply. The change in cost of supply (at different periods of the daily cycle) with an existing capacity, and additional capacity cost arising from capital expansion owing to the characteristics of demand, must be clearly distinguished from one another. Even with the existing capacity, (which is itself a mix of plants of differing efficiencies), energy costs (i.e. variable costs) can vary during different hours. With unevenly distributed demand, plants come into operation in accordance with the rule that the most efficient plants work first, followed by successively less

efficient (i.e. more unit costs of operation) plants in the 'merit order' of operations. When capacity is variable, the costs of supply when demand is pressing against available capacity, may involve additional capacity. This would imply incremental costs of capacity which would be part of the long-run marginal costs of supply. It is equally obvious that, since the capacity of the system (generating stations, transmission and distribution lines, transformers of various types etc.) is determined by the highest demand it is expected to meet (generally referred to as the 'system peak'), there is necessarily considerable spare capacity during the hours other than the hours of peak demand. The theory of peak load pricing, explicitly recognizes these differential marginal costs, and proposes a tariff where the price is time-differentiated i.e. a type of tariff which varies over a daily (or seasonal) cycle, according to the level of kilowatt demand on the system.

Since demand for electrical energy can vary every instant, the problems of applying a time-differentiated tariff, are evident. The metering and other costs of such a variable tariff-structure, quite apart from the costs by way of public inconvenience etc., prevent such an extreme application of time-differentiated pricing. In actual practice, therefore, peak load pricing envisages the decomposition of the load curve (the curve

showing the relationship between the quantity of power supplied and the period of time of supply in the daily cycle) into as many adjacent levels as will properly represent it. As a practical proposition, the number is to be kept as low as possible.*

In a simplified illustration used by Boiteaux, we consider a load curve broken into six independent levels, each level with its own demand, as shown below.

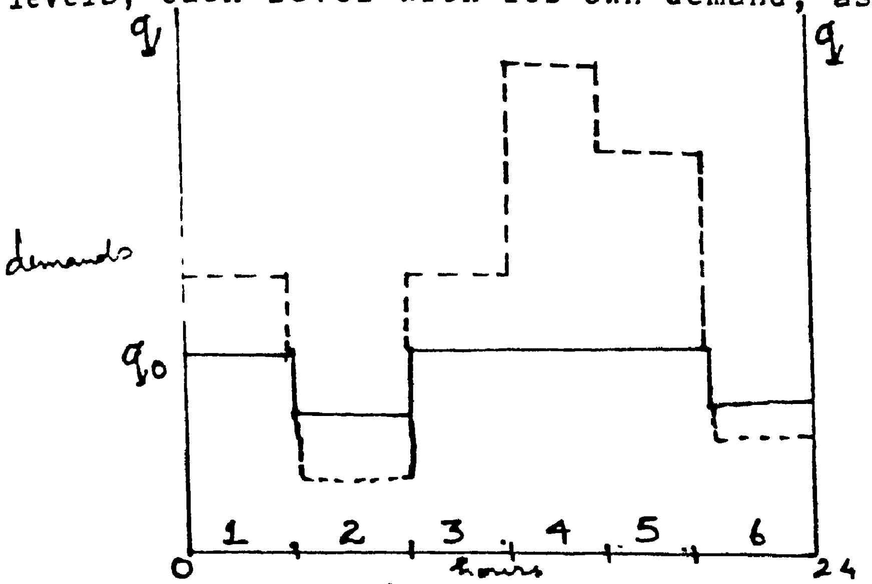

Figure ...Load Curve before and after peak-load pricing; breakdown into six levels (dotted line shows load curve for time-uniform pricing; thick continuous line shows load curve obtained after peak-load pricing)

The principles of peak load pricing in the above model, are basically simple. At every level, prices will be set so that the load curve is brought to follow a horizontal line. If, however, the prices needed to bring demand to this horizontal curve were less than the

* See Boiteaux R. 'Peak Load Pricing' in Nelson (Ed) Marginal Cost Pricing in practice, Prentice Hall, 1964, for a detailed discussion. This is the pioneering article in the field of peakload pricing. See also 'Symposium on Peak Load Pricing', Bell Journal of Economics, Spring 76, Vol.7, No.1.

energy cost* (what Boiteaux calls 'partial cost') for any off-peak levels, the tariff would not be reduced below energy cost, but the load curve will be allowed to fall below the horizontal line. In the above simple model, off'peak demands 2 and 6 bear energy costs only, and demands 1, 3, 4 and 5 are brought down to the level of the horizontal line by a suitable charge for each demand to meet the cost of plant of capacity q_0. Here it must be pointed out, that the horizontality is achieved by the combined action of two forces - (a) direct pressure of the differential price in each period and (b) 'stretching' effect on the load curve, because of interchangeability of the consumption, which partly moves from more expensive periods to cheaper ones.

From the illustration above, it is clear that the time-uniform price (which results in the dotted load curve) is higher than energy cost during periods 2 and 6, and lower during the remaining periods 1, 3, 4 and 5. While the price is lowered to be equal to energy costs during periods 2 and 6, the price has to be raised above energy costs during periods 1, 3, 4 and 5 by adding to it an additional charge (separately for each period) to bring down the curve to the horizontal line as shown above.

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* This could be called 'variable cost' also. We use the term 'energy cost' because it expresses the significance of the concept properly, apart from being generally used in current literature relating to Electricity Economics.

The concept of 'investment responsibility' explains the basis of the charge during the periods 1, 3, 4 and 5. The investment responsibility of an hourly demand is equal to the proportion of the power costs which must be charged to that demand in order to bring it down to the optimum horizontal level. Seen in this light, it is clear that the theory of peak load pricing is but a part of the general theory of long-run marginal cost pricing, where the incremental capacity costs are charged to those periods according to the investment responsibility as defined above.

It is also important to emphasise here, that the relevant peak for peak-load pricing is not the actual peak as derived from the present load curves, but the 'potential' peak. The marginal cost is also based on what the load curves become after the tariff has changed the consumers' behaviour e.g., in our simplified model, the continuous load curve will be the basis of the marginal cost, and not the dotted load curve.* The economic argument for the peak capacity charge, and the favourable treatment (by way of lower price) given to off-peak consumption is briefly that, every peak user imposes on the undertaking and the society in the long run, the incremental cost of the capacity he draws, whereas such a causal relationship does not exist

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* See Boiteaux M and Stasi P. "Determination of costs of expansion in an Interconnected system of Production and Distribution of Electricity" in Nelson J.R. (Ed), op. cit., Chapter 5.

between off-peak use and capacity costs. It would be thus be unfair to levy capacity costs on the off-peak user. Further, in so far as off-peak consumption has any elasticity at all, such a charge would reduce off-peak consumption, and some capacity is left idle wastefully.*

In theory, peak-load pricing can be applied to all classes of consumers. Practical considerations as well as the costs of metering, billing etc. in the case of time-differentiated pricing, have prevented full implementation of this principle even in countries such as France and Britain which have been pioneers in this field.

10. ACTUAL EXPERIENCE OF PEAK LOAD PRICING

It would be instructive to briefly mention the experience of peak load pricing in some countries. The problem really is to strike a balance between an "ideal" tariff with its attendant costs of complexity and the entirely non-time-differentiated i.e. time-uniform tariffs. France introduced in 1956 the first marginal cost based tariff in any major system in the world and applied peak load pricing only to high voltage consumers. This consisted in the introduction of five different daily rates, for each of the six voltage

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* See also Kahn A.E. 'The Economics of Regulation, New York, John Wiley 1970, Vol.1 pp 100-103.

levels of supply. Three of these rates pertain to the (peak) winter months and two to the summer months. The three rates in winter were: (a) the highest rate during the three evening peak hours, (b) "full-use" hours - the next highest rate - covering day time hours, and, (c) the "slack" night hours. In the remaining (summer) months, there were two rates covering "full-use" and "slack" hours only; "full-use" being defined as all the hours other than the "slack" night hours. The winter rates were much higher than the summer rates and the price differential was approximately 4 to 1 from peak to off-peak hours.* The effects of the above tariff were evident after a year of actual experience, when the national load curve was noticed to have flattened out at the peak to the extent of approximately 5%. This meant a reduction of 300MW of peak demand and considerable saving of fuel and foreign exchange. The total economy (including investment on transmission and distribution, which also depend on peak demand) was estimated at more than 50 billion francs for the 7 years following introduction of the new tariff.**

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* Because of increased heating demands the requirements of power increase substantially in winter in France.

** See Pierre' Masse' in Nelson (Ed), op. cit., and also Meek R.L., "Application of Marginal Cost Pricing - the Green Tariff in Theory and Practice", Journal of Industrial Economics, July, November, 1973.

France continues to be an example of the application of marginal cost pricing and peak load pricing to electricity. The latest amendments in the French tariff structure have been reported in the paper by Roux.* The EDF have taken into account the changes in the energy supply structure in France, where the share of oil is declining, and electricity is increasingly being produced from nuclear sources. It has also been found that the seasonality of electricity demand has increased significantly. This is because of a change in the pattern of working hours resulting in a lower growth of consumption during the summer. It is also seen that the daily load curve has flattened out considerably, but the shape of the yearly load curve has deteriorated, and is expected to do so further. Therefore, as Roux observes, there is a "transition in the electricity supply system from a peak of a few hours a day during a good many days a year, to a system whose peak corresponds to a large number of hours the same day, but only during a few days a year, but at dates which cannot be foreseen". The new approach to revising the French tariff takes into account these phenomena.**

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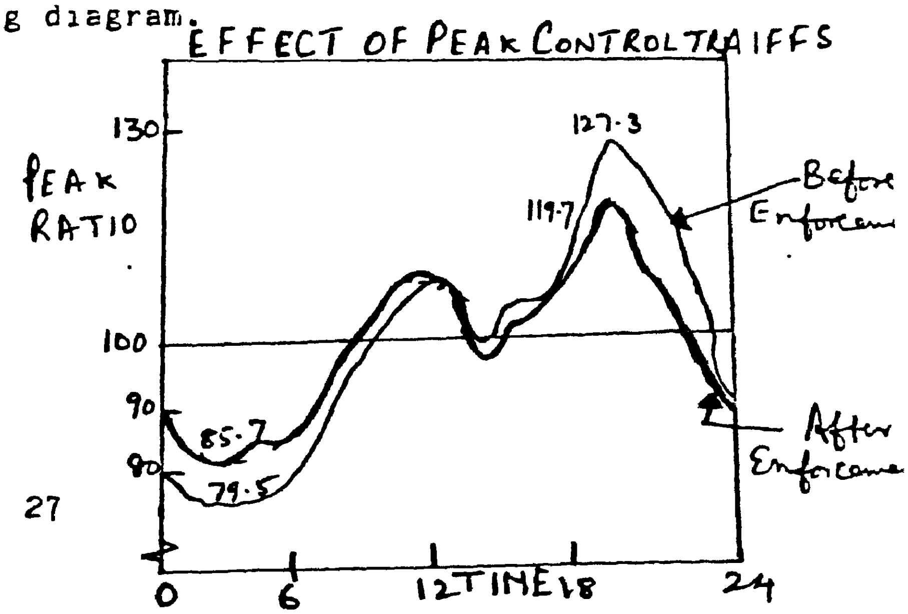
* J.P.I. Roux, "Marginal Cost Pricing : Updating the French Electricity Tariffs", op.cit.

** Space does not permit a detailed discussion of the new French approach. Briefly, the new tariffs will be based on <u>demand</u> rather than voltage. Secondly, since the nature of peak problems has changed completely, the new system proposes a "Peak Day Withdrawal Option" which is expected to enable the EDF to tackle the new peak problem effectively. For fuller details, see Roux, op. cit.

Korea is one developing country which has recently tried to implement peak load pricing. Since the objective of peak load pricing is to flatten the load curve and utilise capacity more evenly, it was important for KEPCO (Korea Electric Power Corporation) not only to know the load pattern, but also to make an assessment of the likely consumer response to the peak load tariffs. In the Korean system, the peak occurred between 5 p.m. and 10 p.m. Apart from calculating marginal capacity cost, and marginal fuel cost, the organization had to make the required forecasts besides deciding on the appropriate pricing periods. In analysing possible consumer response to the proposed peak load tariffs, KEPCO conducted a survey and also utilised an independent survey by the Korean Chamber of Commerce and Industry. Using these sample surveys, they estimated that, by adopting peak load tariffs, the load curves could be flattened by at least 15%. During the 18-month preparatory period, KEPCO explained the forthcoming tariffs to prospective customers. The results of the enforcement of the peak load tariffs are shown in the following diagram.



As seen in the above diagram,the peak ratio (ratio of peak-load to average-load) before the peak tariffs, was 127.3, but it came down to 119.7, and the off-peak ratio at night, increased from 79.5 to 85.7. KEPCO has estimated a possible saving of US $250 million in new investment as a result of peak load pricing.*

11 MARGINAL COST PRICING AND THE REVENUE OBJECTIVE

We have explained how marginal cost pricing of electricity aids in proper resource allocation, by giving the appropriate signals for decision-making in the electric utility industry, especially in the planning of the level of capacity. But it is well known that resource-allocation is not the only objective that the policy makers place before the utility. In most countries, developed as well as developing, the utilities are faced with a revenue objective as well, usually in the form of a required rate of return on capital investment.

The objective of efficient resource allocation leads to long-run marginal cost pricing, as we have explained earlier in this paper. As far as the revenue objective (i.e. a required rate of return on capital base of the utility) is concerned, it is obvious that it

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* For a discussion of the Korean experience, see Yoon Hi Woo, "Korea : Peak load pricing based on LRMC", in 'Costing and Pricing Electricity in developing countries', op. cit., p 295-307.

is an accounting concept, and is thus based on the relationship between average accounting (i.e. historical) costs and price. It has been pointed out earlier that no a priori relationship exists between average accounting costs and marginal costs in a real-life electric utility, with its mix of different types of plants.

Marginal cost pricing may, therefore, result in a deficit, or a surplus that is smaller or greater than the predetermined target, depending upon the actual situation in the electric utility concerned. The conflict arises because average accounting costs are an average of different types and ages of plant, and marginal cost is the incremental cost of new plant at current prices. The observed difference between average accounting costs and marginal costs, can therefore, be very often substantially accounted for by inflation and the firm's accounting practices.

In the short-run situation of excess capacity (i.e. where demand is below the available capacity when electricity is priced at marginal running cost), a financial deficit can arise with marginal cost pricing, as capacity costs are not covered by the short-run rule. However, there is no question of excess capacity in the long run, and we have already explained how capacity costs as well as energy costs are covered by the long-run pricing rule.

The problem then becomes one of reconciling the objectives of resource allocation and the required rate of financial return, the latter being regarded as overriding. Originally, many utility managers and engineers saw in this conflict, the necessity for some sort of average cost-plus pricing, which alone could ensure the achievement of the revenue objective.

From the accounting point of view, long-run marginal cost would include the opportunity cost of capital. Actually, the concept of 'surplus' is purely an accounting concept, and is clearly based on the relationship between average accounting costs and price. What we are advocating is that long-run marginal cost should be the starting point of any pricing policy, and that the revenue surplus (i.e. over and above the average accounting costs) objective, should be considered when making <u>deviations</u> from marginal cost-based prices. In this connection, reference must be made to the important contribution of Baumol and Bradford*. These authors demonstrated for the first time, in a systematic fashion, how, <u>in theory</u>, the demands of resource allocation can be reconciled with the requirements of the revenue objective. Where marginal cost-pricing yields an overall deficit, the

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* Baumol and Bradford, American Economic Review, Vol.60, June 1970.

revenue constraint would require upward revisions in marginal cost-based prices. If we assume that the revenue constraint is overriding, then the problem becomes one of 'optimal' deviations from marginal costs, i.e. such deviations as would cause the least changes in consumption of different categories, from that dictated by marginal cost-based prices. This would imply pricing according to the "inverse elasticity" rule, i.e. maximum deviations in prices of those consumer categories kwith the least elasticities of demand. In the case of a revenue surplus arising from marginal cost pricing, the reverse procedure applies, i.e. maximum decreases in prices of those consumer categories with the least elasticities of demand.*

12. ELECTRICITY PRICING IN INDIA

In this section, we shall briefly review the current state of electricity pricing in India, with a view to suggesting some steps towards a rational pricing policy. The electric utility industry in India is largely under the control of the state electricity boards, each of which has its own set of tariffs. No attempt will be made in this section to review in detail the tariffs of any particular state utility; the objective is more to stress certain common features of their

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* This is the theoretical position. In practice, of course, we often have to 'guess' at the elasticities concerned, as reliable information on elasticities, is usually not available.

tariff structures. The observations made in this section, therefore, apply broadly to all the utilities in India, though there may be some exceptions in certain cases.*

The state utilities have their own sets of tariffs, but the level and structure of the tariffs are broadly similar. Most of them have a two-part (demand charge as well as energy charge) system for the industrial high voltage tariffs, and tariffs consisting only of energy rates for domestic, commercial and other categories of small consumers. All of them have separate tariffs for agricultural pumpsets/tubewells, the growth of which has been an important feature of the development process during the last 15 years.

An important feature of most of the utilities is that they are incurring financial losses, despite the statutory obligation under the Electricity Supply Act, which imposes on them an obligation not to incur losses in their operations. The revenue losses per year exceed Rs.200 crores for all the utilities taken together. The average gross return is less than 8% in almost all

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* Many state utilities have conducted marginal cost pricing studies for their respective jurisdictions. Some of these studies are reviewed in a separate paper by A.Bhattacharyya, "Marginal Cost-based Tariffs in Indian Power Sector - A Critical Review", Discussion Paper, Tata Energy Research Institute, New Delhi, 1984. A general review of the tariffs, with their attendant financial implications, may be found in the "Report of the Committee on Power", Govt.of India, New Delhi, 1980.

cases, and if the interest on capital is taken into account, the net return is almost nil. Different official committees have suggested minimum rates of return on capital employed. An Expert Committee headed by Mr. R. Venkataraman suggested in 1964, that the rate of return should be 9% including depreciation and interest; the more recent 'Committee on Power', suggested a rate of return on capital employed (including interest) of 15%.

An examination of the tariffs in the present day utilities shows that they are much below long-run marginal costs in most categories*. In some cases, such as for agricultural pumpsets/tubewells, the effective tariffs are far below long-run marginal costs. In the electric utility industry in India, LRMC is higher than average costs of power supply, in respect of most consumer categories. Electricity tariffs are below even average costs of supply in some of the major categories, such as agricultural pumpsets.

It has been earlier argued that an ideal tariff would be based on the long-term marginal (incremental) costs of supplying electricity to any consumer. This would depend on the voltage level, the distribution system which serves the consumer in question, and the time pattern of the consumer's demand in relation to the

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* For some figures in this respect, see A.Bhattacharya (1984), op.cit.

system peak/potential peak periods. The need to distinguish consumers into categories, stems basically from the necessity of avoiding complexity in the tariffs. Complexity imposes its own costs (of administration, collection, metering, etc.) which must be set against the benefits likely from such a complicated tariff which seeks to reflect costs in respect of each consumer. Owing to these considerations, consumers are grouped into categories mainly on the basis of similarity in load characteristics.

The question that arises is - whether it is possible to implement a marginal cost-based tariff in the case of the Indian utilities, and if so, what should be the approach adopted? There are two methods of reflecting marginal costs in tariffs for any consumer category. The first method is to estimate the level and time pattern of demand, and the contribution of the consumer-category concerned, to the system peak period, and then arrive at a time-uniform tariff that reflects the marginal costs of meeting this requirement. The second method is to evolve a tariff, i.e. time-differentiated and reflects the costs of supplying these requirement during different period of the 24 hour cycle. The first method is generally used for the smaller consumer categories, in whose case the costs of metering etc. of time-differentiated tariffs, may well outweigh the likely benefits. In the following paragraphs,

a broad indication is given of the approach that can be adopted.

(i) Domestic Consumers: There is no rational economic justification for separate rates for domestic lights/fans and domestic small power. The costs of supplying power to the two categories are the same, except for a peaking element in the case of lighting loads alone. Formerly, such a distinction was made in some state utilities to stimulate the use of electric gadgets, such as refrigerators, etc., but the differential rate has been given up by many utilities. It should be eliminated altogether, especially as electricity is now in short supply and there is no need to stimulate consumption by the relatively richer classes, who will be using electric gadgets. For similar reasons, there should be no distinction between commercial light/fan and commercial small power.

(ii) There are declining blocks in certain categories in some of the state utilities. As costs do not significantly decline in this range, and since there is an overall shortage of power, there is no question of helping capacity utilization by additional consumption in any category. It is needless to add that declining blocks should not be used to stimulate consumption when the need is to conserve power.

(iii) Similarly, in the case of industries taking power supply at high voltage (11 KV and above) there is scope for considerable simplification and reduction in the number of categories to two or three, with rates, of course, for different voltages based on the costs of supply. There is scope for introducing peak load tariffs at least in the case of large industrial consumers. In France, the pioneer of marginal cost-based pricing, time-differentiated tariffs were first introduced mainly in the case of large high voltage industrial consumers. Similarly, in many Indian systems, it will be seen that a comparatively small number (in some utilities, this number is less than 100 and in most, it is not more than 200) of high voltage industrial consumers, are responsible for a significant proportion of total energy consumed. These consumers also are likely to be more responsive to changes in electricity prices, and the costs of time-differentiated metering systems, are also likely to be outweighed by the benefits of this system. Obviously, the introduction of such a system has to be preceded by a period of preparation, as in the Korean example given earlier.*

(iv) Agricultural pumpsets/tubewells:

The tariff in respect of this category, in most

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* Some state utilities, e.g. Gujarat have introduced off peak concessions, but the effects of this limited form of peakload pricing, are yet to be seen.

state utilities in India, has been the subject of considerable discussion in many forums, and hence it is proposed to discuss it in some detail. The important feature of this category of consumption is that it has been increasing rapidly during the last 15 years, especially after the introduction of high-yielding varieties of wheat in the late 60's, which made assured irrigation both necessary and beneficial to the farmer. The number of pumpsets/tubewells in the country has now crossed the 5 million mark, and in states such as U.P., Haryana and Punjab, more than 30% of the annual energy consumption falls in this category. This category of consumption also has a very significant seasonal aspect; apart from this, the load is scattered, and the annual level of utilization is comparatively low, generally around 1000 hours during the year with exceptions such as Punjab, Haryana and U.P., which utilise these pumpsets for around 1500 hours. The Committee on Power has shown how the tariff for this category is substantially below even the average costs of supply in all the utilities.* In fact, this category is substantially responsible for the losses of many State Electricity Boards.

Apart from the overall tariff being substantially below the average (and, therefore, much below marginal) costs, another important feature of the pumpset tariff

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* See Report of the Committee on Power, Government of India, New Delhi, 1980, Chapter 5.

deserves mention here. In many state utilities, e.g. Punjab, Haryana, U.P., Karnataka and Andhra Pradesh, the agricultural tariff is framed in the form of a "flat rate" tariff, i.e. the tariff is charged per horse power of the pumpset, irrespective of the number of hours used. This is against basic economic principles, as the marginal cost of usage of the pumpset is zero in such a case.

It may be pointed out that cross-subsidisation in respect of private tubewells and pumpsets, is generally supported by its proponents on two considerations: (i) The income distribution argument, and (ii) the need to encourage this category of consumption. As far as the income distribution argument is concerned, it is established that the owners of private tubewells/pumpsets, are among the better-off farmers in the rural India.*

Dhawan has made an interesting point about the possible effects of tubewell technology on the efficiency of the traditional means of irrigation, used by small farmers in the vicinity of the larger farmers owning private tubewells and pumpsets. Dhawan points out that there can be a serious problem of lowering of the water table, in the vicinity of tubewells and pumpsets, thus imposing external dis-economies on the

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* See Report of the Committee on Power, New Delhi, 1980, op. cit., chapter 6, for a discussion of this point.

goals of improving productivity and increasing national income, subject to considerations of equity. Apart from economic considerations, it is obviously not possible for the electricity sector to continue to sustain financial losses in the manner it has been doing so far. If a state electric utility suffers financial losses, obviously the losses have to be met from the state's budgetary resources, which would either come from additional taxation, or from some other public expenditure, which is given up at the margin. The social and economic consequences of such an income transfer from non-electricity users to electricity users, are difficult to quantify, but are nevertheless real.

In conclusion, we can perhaps make the following specific suggestions, in regard to electricity pricing in Indian utilities:

(i) Tariffs should move, gradually, closer to long-run marginal costs.

(ii) As the present tariffs are far below long-run marginal costs in respect of many consumer categories, the immediate objective should be to cover atleast average costs in each category, (to the extent they can be estimated) i.e. there should be no revenue losses.

resources of traditional wells.* The income distribution argument, therefore, does not support the subsidy being given to private tubewells/pumpsets. It is also doubtful whether the "stimulation of consumption", argument would support a subsidy. There is reason to believe that demand for irrigation water will be inelastic over a considerable range of the price of electricity.** There are other reasons also for bringing the tariffs for agricultural pumpsets more in accordance with the long-run marginal costs. A recent study has shown that, though electricity-driven pumps are economical from the private point of view, they do not compare very favourably with some other alternatives such as diesel-cum-biogas or even diesel-run pumps, if _social_ costs are considered.***

13. TOWARDS A RATIONAL ELECTRICITY PRICING POLICY

The objective in a developing country such as India, is obviously to utilise the national resources as economically as possible to achieve the stated economic

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* Dhawan, B.D., "Review of Agriculture", Economic and Political Weekly, June 21/28, 1975.

** The elasticity of electricity demand can be as low as 0.24 as shown in a study by Dhawan, B.D., "Demand for Irrigation", Indian Journal of Agricultural Economics, April/June 1973.

*** See Ramesh Bhatia and Armand Pereira (ed.), 'Socio-Economic Evaluation of Renewable Energy Technologies', International Labour Organisation, Geneva, 1984, Chapter V, for a detailed analysis.

(iii) Subsidies, if at all necessary, should be confined to essential, socially justifiable and specific categories such as street-lighting, domestic electricity supply in remote rural areas, small and marginal farmers, etc.

(iv) There should, in any case, be no subsidy for energising (profitable) economic activity, viz., irrigation, industry etc.

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Generating Capacity Planning in Electric Utilities

by Dieter Nitz

Hamburg, den 8.7.88

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C O N T E N T S

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Introduction

High capital intensity, the increasing scarcity of raw material sources, the demand for action in the field of environmental protection and other challenges from the public and politics make it imperative, not only in the Federal Republic of Germany, for enterprises to exercise ever greater care in their corporate planning and for departmental planning within an Electricity Supply Company (EVU) to be coordinated. The companies have to face the growing tasks they have in this respect with continuously more effective methods of planning and management.

These requirements are irrespective of whether the electricity sales of a company increase or not.

Generating Capacity Planning as part of Corporate Planning

More and more of the electricity supply companies (EVU) in the Federal Republic of Germany have started, within the framework of their long term planning, to illustrate the business operations of the whole enterprise with the aid of electronic data processing (EDP) models (i.e. Corporate Planning).

In this connection, Generating Capacity Planning on the one hand can be identified as expansion planning for production. On the other hand, the planned extension of capital-intensive power stations will also lead to an expansion of the whole enterprise, which through the increase in fixed assets, finds its way right into the balance sheet.

A reliable evaluation of this process necessitates a general view of the enterprise. Especially the economic effects of the extension of power stations should be assessed within the accounting section, more specifically, for example, through the profit and loss account, <u>before</u> a decision is made.

An EVU simulator could be provided for this with models for:

sales, delivery/distribution, production, fuels-management,
investments as building activity for distribution and production, personnel, finance accounting with profit and loss account, balance sheet and finance plan

Being interdependent, these functions, where partial

planning of the enterprise is carried out, have to be tied up with the whole enterprise (enterprise model).

The direction these ties take is not incidental, because

sales = demand for electricity
meeting the demand for electricity = production requirement
production = fuels requirement
procuring of fuels = financing requirement
etc.

Expanding EVUs in particular are permanently faced with the question of what is the correct strategy for the expansion of their power station capacities, whether this be to replace old plants or to meet the expected increase in demand for energy.

In view of the manifold combination possibilities, not every expansion alternative can be examined in a large EVU-simulator.

It is the task of Generating Capacity Planning to evaluate and select favourable power station extension sequences as expansion planning.

Capacity Planning as Expansion Planning

General Information

Because of the long service life expected from generating units, the long-range implications of any near-term decision have to be considered. This means that the planner, though primarily interested in the next installation requirement, should make his decision based upon its compatibility with an economic long term expansion strategy.

But evaluation cannot only be based on economic criteria, it also has to take into consideration supply aspects, e.g. reliability of supply. In view of the numerous possibilities for the combination of expansion sequences, a deterministic solution with a clear objective is not possible. What is necessary is a plan for a progressive and iterative solution of partial problems.

Much reliance is placed on the judgement of the planner to select the most promising alternatives for simulation.

Nevertheless, the growing number of alternatives available and increasing pressure due to utilities' financial constraints to "plan smarter" have reinforced the need for better planning tools.

3.2 Essential Elements of Capacity Planning

Capacity planning has to develop alternatives to cover the expected load increase, and in this respect the target has to be borne in mind. The main objective is: to identify system design patterns that will produce the maximum economic return for the utility.

The following elements and steps of capacity planning can be stated:

- drawing up of the capacity balance as a comparison between power station capacity and maximum load

- identifying supply reliability, which must be comparable for all expansion sequences

- making use of the composition possibilities according to
  - types of power stations: thermal power stations
hydro-electric power stations
pumped storage power stations
  - fuels: nuclear fuels
coal
natural gas
oil
  - interpretation: basic load
intermediate load
peak load
  - unit capacities: large
small
standardized or not
  - structure of costs: high investment costs/
low fuel costs
low investment costs/
high fuel costs
  - development of a mixing strategy
  - taking into consideration the peripheral conditions set by the locality factors, such as delivery and distribution network, environmental load, coal mines, availability of cooling water, deepwater ports
  - fixing the planning period
  - evaluating the extension sequences
  - selection of a few, more suitable extension sequences

- proposals for decision.

3.2.1 Balance of Load and Capacity

The expected or anticipated development of electricity sales also includes, through the anticipated load structure, the projection of the maximum annual load. This represents the development of the maximum consumer demand.

This demand must be met by power station capacity in such a way that the supply reliability required is always guaranteed.

The balance of load and capacity is understood to be the comparison of maximum load demand with the sum of the power plant capacities. The composition of power plants must take into consideration:

- the reliability of supply
- operating procedure (control of the system)
- the economics of electricity generating.

The operating of an electricity system requires two groups of power plants: one group for covering the load at any time of the day under normal conditions, the other one serves as reserve capacity. The first one contains suitable plants for covering the basic, intermediate and peak load.

The reserve capacity resulting from the calculation of a capacity balance represents the difference between installed power station capacity and maximum annual load.

3.2.2 Service Reliability

We define service reliability as the ability of a power system to meet its supply function under stated conditions for a specified period of time.

Determination of the reserve capacity required

As no technical system nor any power station can be operated for a lengthy period without failure, power station reserve capacities have to be planned for cases of failure.

If the failures are recognized as being accident-dependent the problem can be approached with models of probability theory. The power station unit is the smallest statistical unit in this respect. The certainty of always having the necessary capacity available cannot be absolute with the available power station capacity limited and the possibility of failure within the production plants, but will be equivalent to a probability value, which can be

very high. But there remains an unavoidable risk of failure. The clearest form in which to represent this problem is the outage duration curve, which results from the combination model. This is based on the calculation of all combinations of the individual failure probabilities. Each of these combinations has a capacity, this being the sum of the non-failed power stations, and a probability, which is the product of the failure probabilities and the availability of the individual units.

The following assumptions are made to explain the mathematical concept:

There are n-machines M_i (i = 1---n) with a generator capacity of p_i, which are connected with one another within a network. Each of these machines has a failure probability of p_i and thereby an availability of $q_i = 1-p_i$. The failure characteristics for all machines can only have two conditions: in operation (=1), not in operation (=0). (Partial limitations in operation are not taken into account in this calculation.)

When determining the failure probability with regard to the whole system, every possible outage situation is considered separately. An outage situation represents a possible combination of failed power stations and those ready for operation.

The failure probabilities for the individual outage situations are as follows:

Conditions of n power stations for all failure situations

situation	M_1	M_2	M_3	...M_n	
A(0)	0	0	0	0	$w_o = p_1 x p_2 .... x p_n$
A(1)	1	0	0	0	$w_1 = q_1 x p_2 .... x p_n$
A(2)	0	1	0	0	$w_2 = p_1 x q_2 .... x p_n$
A(3)	0	0	1	0	
A (2^n-1)	1	1	1	1	$w_{2^n-1} = q_1 x q_2 .... x q_n$

The total number of outage situations is thus 2^n. For each outage situation A(i) the available capacity is arrived at by adding the nominal capacities of the available power stations.

The outage duration curve shows the output failure on the ordinate according to its extent, and on the abscissa the relative failure duration (failure probability).

This enables the question to be placed of what reserve is necessary resulting from an allowed failure risk. This

risk also determines the failure capacity allowed. If a reserve is held available to the same extent, an assured capacity can be described:
the capacity thus assured corresponds to the total capacity installed less the allowed failure capacity which is determined by the failure risk.

If the assured capacity is equivalent to the maximum annual load, the failure risk indicates how often or for how long this load cannot be covered by the described group of power stations.

Small failure risks or, put the other way, high supply reliability, do however mean that a high reserve capacity is necessary. This means that a high supply reliability leads to high costs for the generating of electricity. As a planning criterium always involves a minimization of costs, the demands are for high supply reliability and low production costs to be weighed up against each other, as each basically contradicts the other.

In EVUs in the Federal Republic of Germany, which determine what reserves are necessary by means of probability theory models, the allowed failure risk is put at 3%. This leads to reserves being necessary which are 20% to 25% of the maximum annual load.

Provision of Reserves

Although the reserve capacity requirement is clear, the question still remains: in what form will this total capacity be provided?

It is the basic task of the power station reserve to provide reserve capacity P_R, after a failure in the generating capacity P_{out}, to the same extent and in good time. This, taken as a whole, leads to four very different types of reserves with a dependency on time. The instantaneous and second reserves are characterized by automatic system processes, the minute and hour reserves are not.

Instantaneous and Second Reserves

In interconnected and intact grids, the sudden failure in capacity by a grid partner is of necessity physically replaced from the participating second reserve of all grid partners.
Within the West European grid network the largest machines with 1300 MW take a share of less than 1% of the UCPTE (Union pour la Coordination de la Production et du Transport d'Electricité) total output. But this share, taking all the grid partners, is certain to be a participating control capacity or second reserve in the

network. If it is assumed that the capacity failure is made up pro rata by the individual grid partners, the second reserve does not necessitate any particular expense for normal failures. The case is different with smaller grids or island networks (see developing countries). For instance, the failure of a 400 MW unit in Java brings with it a loss of more than 16% in generating capacity, which calls for a markedly higher participating control capacity.

Minute Reserve

When a capacity failure has taken place, the second reserve is intended to be replaced by the minute reserve without any substantial delay. A German grid company (DVG) agreement in the Federal Republic of Germany, for instance, provides for this to be done within 3 minutes if possible, at the most however, within 5 minutes.

Suitable plants for the provision of the minute reserve are quick-starting gas turbines or pumped storage power stations. The utilization of these plants, too, should be replaced by the permanent reserve as quickly as possible.

Permanent Reserve

The assessment of the permanent reserve is based on the total reserve requirements determined. Pooling with other partners in the grid also makes it possible to have gas turbines (which are capable of operating as minute reserves) available as part of the permanent reserve.

3.3. Evaluation of the Expansion Sequences

3.3.1 General Information

As long as the individual steps and elements of capacity planning are not included in corporate planning as a whole, in other words cannot be made part of the enterprise simulation, all that remains as an evaluation criterium for expansion sequences is the preinvestment analysis, which takes the form of a comparison of all income and expenditure. If, with the expansion sequences under comparison, there is no difference between the respective incomes (which is usually the case), then the problem becomes a mere comparison of the respective expenditures. In the static form of the preinvestment analysis, one simply brings into the comparison the sum of all annual expenditure for the whole of the planning period. High expenditure at the end of the comparison period plays just as important a role as high expenditure at the beginning of the period. If the expenditure shows the enterprise to have money requirements which have to be

met by financing, then the static approach is not a suitable one for the evaluation of an EVU's expansion sequences. This requires a cost model.

3.3.2 The Cost Model

A suitable method of evaluating investments and other expenditure - this also applies to EVUs - is to apply present worth arithmetic. The interest rate for the calculation is of major importance with this method.

This interest rate is an anticipated model for an assumed financing structure and tax burden. Hence the interest rate represents both financing in the form of equity (e.g. shares) and borrowed capital (e.g. loans), and the taxing of capital and yield (profit). (This is where we find the strong interface in the direction of an enterprise's finance and accounting section.)

Once a suitable interest rate for calculation has been fixed, the cost model operates in accordance with the rules applicable to the mathematics of finance.

All annual costs of an extension sequence, that is

capital costs
operating costs (fuel costs)
personnel costs

are based on a specific discount time and become, through the interest rate, annual present values which can be accumulated to become the sum of present values over all the years.

By adding up all annual expenditures and using present worth arithmetic, it is possible to determine the present worth of all revenue requirements of a particular expansion. Comparing the values of these different alternatives indicates the most economical approach.

Often, power station alternatives with differing capacities are to be made comparable. In such cases, it is recommendable to translate the present values into specific costs (pfennigs per kWh). It is necessary to fix the estimated useful life (depreciation period) for this calculation, too. With the aid of the calculation interest rate, the annuity of the present value of all expenditure - this includes investment expenditure - can be calculated and divided by the amount of electricity generated annually.

A mathematical equivalent is the division of the present value of all expenditure by the present value of all electricity generated. The identifying quantity thus

calculated is also called "a power station's electricity generating costs during its whole depreciation period (e.g. 20 years), calculated according to time-adjusted methods". This quantity marks the relative advantageousness of the production plant, but it does not express any specific costs incurred in a certain year. The electricity generating costs thus calculated cover all investment, fuel, operating and maintenance expenditure and taxes and interest connected with the project.

3.3.3 The Investment Model

The evaluation of extension sequences is in essence also an evaluation of the investments, the expenditure for constructing power stations. In the cost model, the fixed charges are taken from this.

Significant factors in determining the fixed charge amount are the construction period and the payments for construction as work progresses. A long construction period for capital-intensive power stations can quickly lead to present values with regard to construction expenditure which are more than twice as high as the nominal value. It is even more important that the construction periods be adhered to if increased expenditure (price increases) are to be expected.

In the investment model, a power station's construction phase must therefore be illustrated realistically as to its timing, so that the fixed charge amount can reliably be determined and the investment risk assessed.

3.3.4 The Production Model

Just as the investment model illustrates the investments and the building progress of all power stations in a construction sequence, a production model must simulate as realistically as possible the use of all power stations in operation in each year of the overall planning period. It is the aim to maintain the load for each power station in the construction sequence and for each year of planning. The amount of fuel consumed is determined by the power stations in operation. Fuel prices for the respective fuels are the criterion for fuel costs, the largest part of the operating costs of a group of power stations in the case of thermal power stations.

The real Production Model

A production model which is to be used for production planning - and not only for capacity planning - must contain load models on the basis of day-to-day characteristics. Such a model is described in Annex No. II. This model has been used for years at HEW, Hamburg

(Hamburg's electricity supply company), for both production planning and capacity planning, and has proved to be a successful model. It is one of HEW's own developments. Analysis and construction recommendations become evident from the detailed description. It is no longer possible to comprehend models of this size without computer support.

The simpler Production Model

A simpler approximation to a production model is based on the load model "load duration curve".

If it is the aim of planning to maintain the energy supply of one year, not split up, in the form of the annual figures only, then the duly set out annual load duration curve can be a suitable medium to illustrate the structure of demand. This curve is a two-dimensional illustration, in which the load is shown on the ordinate according to its extent, and on the abscissa according to how long it has lasted - irrespective of when the load occurred. As the curve therefore does not show when a load it represents occurred in the course of the year, the annual load duration curve is not suitable for illustrating the distribution of the load. It is, however, approximately suitable for illustrating the energy dispatched annually (in GWh), viz. in the form of an area below the curve, split up amongst the sources available taken as an annual average and listed in order of importance.

The load duration curve is drawn to show the maximum annual load on the ordinate and the number of hours per year, 8760 h, on the abscissa. The area below the curve is equivalent to the annual energy to be dispatched (total production).

The annual load duration curve model can be realized with an appropriate mathematical function, even if it only shows the maximum annual load and the annual power supply, whereas the structure of power consumption is unknown.

Limits of application:

> The annual load duration curve is an instrument for the dispatching of energy, not of load.

Which of the available power stations is to be used on the strength of the annual duration curve is determined by their respective areas being divided up into stripes from bottom to top. Each stripe area corresponds to the use of a power station. The sequence of use (hierarchy) is based on fuel costs. Power stations with the lowest fuel costs are put into operation first. The contribution a power station makes towards meeting capacity requirements

- the width of the stripe - is equivalent to its own capacity, reduced by the availability factor (<1). This simple approximation procedure can also be used manually, without computer support, for simpler problems.

3.4 Selection, Sensitivity Considerations

Selection can be understood to be part of an iterative process. The possible extension alternatives are examined in the form of sensitivity analyses to determine how they react to changes in the initial parameters, e.g. unit capacities, fuels, cost structure, price increases. Only after this examination has taken place can a few suitable and usable alternatives from the many alternatives possible be put forward in the form of a proposal for deciding upon. Details of some connections are given below, though these do not claim to be complete.

Unit Capacities

Although large units have smaller specific construction costs (dollars per kW), they necessitate a higher reserve. For smaller enterprises in particular, it can be more expedient, even with high growth rates, to choose smaller plants to avoid the cost of carrying large amounts of unused capacity. Large units operating not to their full load capacity have a poor efficiency factor and thus record high fuel costs. A system composed of a few large units is much more seriously handicapped by a shutdown of one of those units than a system comprising many smaller units (see section 3.2.2). Uncertainty over demand is another good reason for small plants. "If you are wrong with a big one, you are really wrong. If you are wrong with a small one, you can just put up another." (An American manager).

Base Load and Peak Load

In a balanced system, different types of generating are added to the system in such proportions that the more efficient units will have lifetime load factors higher than average. This expansion pattern offers the possibility of maximizing the effect of the good characteristics of each type and of minimizing the effect of unfavourable ones.

It can be shown that peak equipment properly integrated into a system expansion can provide greater savings than the predicted improvements in the efficiency of base load units. Furthermore, peak equipment complements and therefore enhances the saving potential for advance cycles, such as nuclear power plants.

Oil-fired gas turbines or quick-starting steam power

Erzeugungskosten verschiedener Kraftwerkstypen

Kraftwerkstyp	Investitionskosten pro kW bereitgest. Leistung in DM	variable Erzeugungskosten in DPf/ kWh 1)	Erzeugungsgesamtkosten in DPf/kWh
Kernkraftwerke	4000 - 5000	3	10
Braunkohle-KW	2500	3,8 - 4,5	7 - 8
Steinkohle-KW	2000 - 2500	10 - 12 2)	15 - 20
		6 - 8 3)	11 - 13
Öl-/Gas-KW	1000 - 2000	13 4)	21,5 - 24,5
Gasturbinen	400 - 500	21 - 25	30 - 36

1) Brennstoffkosten einschließlich Umweltschutzkosten bzw. Entsorgungskosten
2) Bei Nutzung deutscher Steinkohle
3) Bei Nutzung von Importkohle
4) Bei Zugrundelegung der Preise von 1985

Quellen: VDEW/BGW/AGFW (1984), Prognos (1986), ISI (1986), Angaben von PreussenElektra und vom Badenwerk

stations - also oil-fired - of the simplest construction type (e.g. those without intermediate reheating) are considered to be peak load plants.

Nuclear power stations are typical base load plants. They have high construction costs and low fuel costs.

The situation is reversed with gas turbines - suitable for use as peak load plants and reserve plants.

The investments made in coal-fired power stations, which in the Federal Republic of Germany are intended to meet the intermediate load demand, are noticeably lower than those made in nuclear power stations.

The Structure of Generating Costs

When a direct comparison is made between two types of power stations where the load factor varies, there are often operational areas to be found where the total generating costs are the same. These break-even points can be in the areas meeting peak load demand or meeting base load demand. In the comparison of nuclear power stations with coal-fired power stations, the break-even point is to be found in higher load factors. This means both types of power station can be used to meet the base load demand. Both, however, have widely varying structures as regards their generating costs. It can be deduced from this that:

If a load is not guaranteed indefinitely to be within the area of the break-even point, the coal-fired power station is more advantageous. If a better load can be guaranteed, the nuclear power station will be more economical.

Fuel Mix

Electricity supply companies with a large share of thermal power stations also have great fuel requirements, fuel being a primary energy source. History has taught us that to secure the existence of an electricity utility in the long term, the dependence on one type of fuel should be avoided. This applies in particular to fuels which have to be imported. Since the oil crises (oil price crises) sparked off by the conflicts in the Middle East, the public electricity supply of Western Europe has been faced with the challenge of turning away from oil as a fuel for generating electricity. This has almost been achieved within one decade. For instance, in Hamburg, fuel oil can practically no longer be used at present for generating electritity. The use of fuel oil is controlled by a federal authority. The possibilities for using natural gas are consequently likewise becoming ever more restricted.

Environmental aspects are in the way of the increased use of coal. As to nuclear fuels, the problem of their acceptance amongst the general public is a hindrance to their being used. This experience thus shows that particular attention must be paid in capacity planning, too, to a systematically balanced fuel mix being used.

Pumped Storage Hydro

As with any form of peak equipment, pumped storage hydropower is installed to reduce plant investment. However, its effect on total system operating costs can be quite important. Therefore, even for a planning study, it is necessary to have a production model, which will accurately simulate the actual system operation (see section 3.3).

This model must integrate the operation of one or more pumped storage installations with the thermal sources of a system. This requires an economic scheduling method which ensures optimum formulation of the pumped storage cycle over a period of a day, a week or more. This scheduling method must observe all physical constraints, such as cycle efficiency, pump and generator ratings, and reservoir storage.
Sequential hour-by-hour dispatch must be simulated, based on the incremental fuel cost of the thermal units.

3.5 Proposal for Decision

The favourable construction sequences shown by generating capacity planning do not yet replace the decision to build an additional power station (or stations). At the most, these can be regarded as proposals for the decision process.

It should be pointed out that the capacity planning dealt with so far should also be seen as part of comprehensive corporate planning (see section 1). According to this, before an investment decision is made, there is still the question to be gone into of whether apart from the operational efficiency calculated in accordance with the rules of preinvestment analysis (present worth mathematics), there are also the actual prerequisites for the extension of capacity, such as

- sales
- financing
- profit (profit and loss account)
- fuels supply
- power distribution
- locations, cooling water

and last but not least environmental compatibility.

The calculation of the operational efficiency of an extension alternative by no means includes the evaluation of all risks. The present worth calculation method does, after all, only enable the most varied expenditure to be added up. Attention is drawn to the investment risk:

The decision to construct a power station immediately triggers off investment payments. The larger the power station is and the greater its capital intensity, the higher these investment costs are. This higher immediate expenditure in comparison with less capital-intensive alternatives is opposed by expectations of making fuel savings in the long term and indefinitely.

The investment risk lies in the large time lag between incurring the expenditure and the expectations of savings.

Conclusions, Experiences

Capacity planning - numerous methods of the most varying kinds can be used to carry this out. A solution optimal for the whole enterprise cannot be found deterministically by using one single mathematical objective function. However, by iteration and by the gradual solving of partial problems, favourable extension sequences can be chosen which are included in a proposal for decision once they have undergone sensitivity analyses. The variety of partial problems to be solved can - at least in part - necessitate the use of computer-aided models.

The author's several years of experience in the development and application of suitable methods and models for corporate and capacity planning at Hamburgische Electricitäts Werke (HEW) show that:

1. Every enterprise has to develop its own models philosophy and make its own decision with regard to the sense of using models for corporate planning.

2. Capacity planning can be conceived as an independent planning function, but it must nevertheless also be regarded as part of comprehensive corporate planning.

3. Capacity planning can facilitate decision making, it cannot replace the decision.

4. The proposals put forward with the aid of models have to be comprehensible to those making the decision, see Woolsey:

   "A manager would rather live with a problem he cannot solve than accept a solution he cannot understand."

5. It is better to adopt a simple approach to problem-solving than to apply complicated procedures not necessarily suited to solving the problem.

6. Caution should be exercised when acquiring ready-made large-scale solutions offered by external sources but not dealing with the actual problems of an enterprise.

7. By gradually extending the methods applied, it is possible to include experience gained and more reliable data in the development.

8. The development and use of models in electricity utilities must be regarded as an interdisciplinary task with overlapping cooperation within different areas. In this respect, the energy engineer has to acquaint himself with the terminology of a businessman - and vice versa.

The Model in the Planning Process

The following comments are based on the Seminar "Draft of Planning Models" which was held by Prof. Müller-Merbach in November 1980.

1. The importance of models

"Notions without concepts are blind,
concepts without notions are empty."

This sentence was written by the German philosopher Immanuel Kant (1724 to 1804). The meaning behind the sentence represents the fundamental state of affairs within communication, the daily round of social intercourse.

On the one hand one cannot recognize nor speak about objects (e.g. power station, combined heating and power station, boiler of this power station), qualities (e.g. old, large, clean) and events (building, operating and shutting down), if one does not have the respective concepts. On the other hand, concepts are of no use for cognition if one has no idea of what they mean. Everybody who tries to take up specialized literature without the basic knowledge experiences this. The language a specialist in an unknown field uses is not understood.

If one calls links of concepts a model, then everybody deals with models daily. They can be evident and pictorial like

- a photo, an X-ray photograph
- a street map
- a timetable
- a mathematical equation

or they may consist of parts of consciousness, as follows:

An accountant may think up a balance sheet model of every EVU (electricity supply company). A heating engineer presumably sees the electricity supply as being more in the form of a heat-circulating scheme.

The following definition of a model also serves our purpose;

" A model is the illustrating by subjects of an object whose composition is such that it allows the same or other subjects to absorb knowledge of the object."

The subject (that is: man) is seen as having a double function here: as the constructor of the model and as the user.

Draft of the Model

The object has its effect on the subject, this means the subject becomes aware of the object. A model is formed of the object perceived.

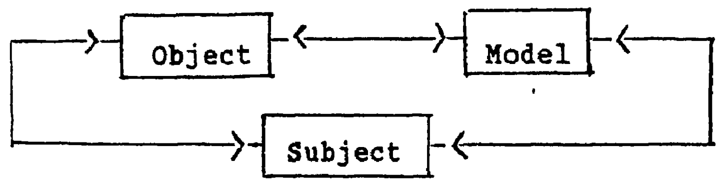
$$\boxed{\text{Object}} \longrightarrow \boxed{\text{Subject}} \longrightarrow \boxed{\text{Model}}$$

Application of the Model

The subject is situated in another place. The subject works (plays) with the model and through it receives cognition in respect of the object, from which it draws its conclusions.

Subject → Model → Object

If one places the subject, i.e. man, to the fore, this yields a triangle of action:



- The relationship between the model and the object is of a passive nature in the sense that neither can use this relationship for any actions. It is impersonal, because an existing model represents an illustration of the object freed from personal interpretation.

- The relationship between model and subject, on the other hand, is of an active nature. This relationship does not become existent without action on the part of the subjects. This action may concern the draft of the model or the use of the model for the purpose of cognition in respect of the object. In the case of such a "dialogue", the model serves as a "bridge" leading to the object. As such, the model has a considerable influence on the extent, the contents and the tendency of the user's cognition.

- The relationship between object and subject are also active in both directions. On the one hand, the subject can influence the object (e.g. the enterprise) through decisions (e.g. target-alterations). On the other hand, the object has its effect on the subject in various ways, if for example it is borne in mind that the object is the enterprise and the subject an employee (the planner).

2. The Subjectivity of the model constructor and the model user

It is often assumed that objectivity can be assured in judging an object if models are used. This is not possible, nor is it desirable, as can be evidenced.

The model constructor has the task of forming the model of an object, for instance the model of an enterprise (EVU). His doing this depends to a very significant extent on his philosophy of life and his pre-comprehensions, which are for instance marked by his psyche and training (see section 1).

Similar statements apply to the user of a model. He works with the model and has to interpret the results. The interpretation is subjective and individual. But it is only through this that the results gain their value. In this respect, too, the philosophy of life and pre-comprehensions of the user of the model play the main part. It goes without saying that first of all the model has to be accepted before the results can be used, otherwise communication through the model as a "bridge" would not occur at all, see Woolsey:

> "A manager would rather live with a problem he cannot solve, than accept a solution he cannot understand."

We can state: model results only become relevant through the user and dynamic through his interpretation.

3. Function and Determination of the Model

The model constructor and the model user are thus dependent on interpretation. Everything around the model is subjective and changeable, thus making the model itself appear to be a "rescuing rock". As soon as a model exists, one can work with it and concentrate on it instead of on the object it represents.

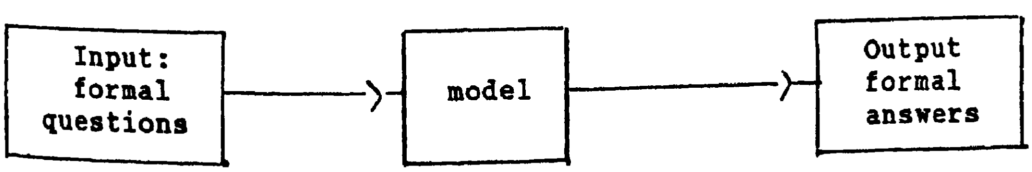
Thus the main task of the model constructor is to transfer the objective to the model in such a way that this functions - as in reality - clearly, logically and consistently. This procedure is also tautologization of new information logically, but the model does contain all reality-related information in an explicit or implicit way.

Example: A model $3x + 2y = 6$ is given of an object.
All that can be done using this model are tautological operations (those free of interpretation).

One can resolve	$y = 3 - 1.5x$
and ask how large y is if	$x = 2$
The answer is clearly	$y = 0$.

Tautologization is an essential process of development, especially with mathematical models, for instance planning models. It is only through this that the function of the model, being free of interpretation, and in the last resort the transfer to machines (e.g. digital computers) are guaranteed.

<u>"Formal questions"</u> can then be put to the model and information fed into it. <u>"Formal answers"</u> or information output will be the result:



The formal answer demands interpretation. The <u>subject</u> is necessary again for this. But now, it does not carry out a tautologization, but a "<u>de-tautologization</u>".

Summarizing this, we can thus state:

- Only people (subjects) can illustrate objects through models. This activity is strongly marked by subjective conditions (philosophy of life, pre-comprehensions). It is therefore not surprising that various model constructors design different models of the same object.

- Once a model exists, it can be used to carry out operations free of interpretation (tautological operations).

- The results of the tautological operations again need interpretation and are thus dependent on subjective conditions.

4. Philosophy of Life and Pre-comprehensions

If "philosophy of life" is interpreted as a personality characteristic of man himself (subject), then pre-comprehension is a first relationship (approach) between subject and object. Both concepts are combined. The philosophy of life determines the pre-comprehension with which a person approaches an object. The pre-comprehension in turn marks the draft model and the interpretation of model results.

The ability to see an object hence arises from a person's philosophy of life, which is based on his psyche, his education in its broadest sense and system of values (ethical, religious, political ties).

5. Cooperation in Overlapping Spheres

The subjectivity of the individual draft model and the individual use can also be illustrated by the use of analogies (see enclosed analogy table). It can be taken from this that with education becoming more specialized, the understanding among the various persons will decrease. The consequences are obvious.

In colloquial usage, the statement is all too often heard: "This is a commercial problem", or: "This is a technical problem".

In reality, there is no problem which could be related to one single discipline. At the most, there are physical, technical or commercial aspects of a problem. One can follow up these aspects independently of one another. If the object to be modelled is seen as the overall problem, then cooperation in overlapping spheres already becomes necessary for the draft model.

Enclosure

Imagine that different persons with varying psyche, educations and systems of values are to consider the same object and model it (at least mentally), and they are to interpret statements (model results) on the object. They will show totally different reactions.

Example: Let us make the object a house with many windows. The subjects are persons with various educations. There is one window for each type of education through which the corresponding persons look into the house, i.e. the physicists through the physicists' window, the sociologists through the sociologists' window, the technical designers through the designers' window, etc.

As these windows give views of different rooms, there will be various perceptions. Some will see into the cloakroom, others into the living room or into the kitchen, yet others into the coal cellar etc.

But even if all were to look through the same window, they would not see the same thing. One is interested in the china, the other in the cupboards, the third person in the carpets, the fourth in the pictures on the wall, etc. Though they can discuss what they see through the same window, they will probably not be interested in what the other observes.

Now one would after all think that two persons looking through the same window - who have similar systems of values, i.e. with the same education - will arrive at very similar insights and judgements. But there is no guarantee of this, either, because they might have a different psychical structure. The one may primarily be a sensitive person and see the objects observed as such, whereas another may - as an intuitive person - immediately think of alternatives, mentally exchange vases or see the empty table festively decked with food and wines. The "thinker" may see a geometrical order in the room or calculate the size of the room with the aid of the floor tiles counted. The "feeling person" on the other hand would perhaps give thought to how people live together in the room.

This analogy serves to show why understanding between various persons can be so difficult. The closer the persons stand to the window and the more intensively they see the object of their choice and reflect on it, the greater the difficulties of communication become.

But it is the very proximity to the windows which most of the mono-disciplinary courses of education at the universities and technical colleges support. The physicist is educated for the view through the physicist's window, the sociologist for the view through the sociologist's window, etc. And each discipline claims that its window is actually the one which makes a particularly good view into the house possible.

Source: Prof. Müller-Merbach "Draft of Planning Models" Seminar, Nov.1980

Analogy Table

Energy Production Planning using flexible Load Models

1. Introduction

Fuel costs represent by far the largest part of operating costs for an Electric Supply Company, e.g. HEW, which has to cover the current demand in its own supply area from thermal power stations, which in part also provide district heating. The minimization of fuel costs thus becomes a major task of "load distribution", which presents the use of available sources to meet the load in accordance with optimization criteria.

Long term energy production planning means simulating the function of "load distribution" well in advance.

Experience shows that the planning horizons have to be broadened to an ever increasing extent. At present it is quite customary to plan up to the year 2000 and thereafter. Such long planning periods make special demands on the EDP models as to their flexibility and variety of usage. Not only do the most varied mixes of the available production sources have to be played out, it also has to be possible to assume extreme developments and alterations concerning sale and load structures. The standard question to be gone into with the system described here is: "What if ....?"

There are two different problems to be solved for each line of business (electricity and district heating):

- In load models all sales expectations have to be changed to time-dependent load processes (characteristics).
- In supply models the usable sources for covering the load have to be specified and all essential operation criteria defined.

2. Load Model for Electricity Generating

Under simulation of the load distribution function, the load model for electricity generating has to lead to day-load curves, i.e. to the illustration of the load course over 24 hours of a day.

At the beginning of model development is the analysis, and here it is expedient to start with the breakdown of the sum-load.

The HEW load distributor measures 4 sectors, which are accessible to a separate analysis. Included are the supply to two large customers and the delivery to an adjoining EVU. This is carried out according to schedule which can be directly transferred.

The remaining load of the supply area proper is called main load. As this load must take seasonal influences into account and follow the life and work rhythm of the population, it is subject to considerable fluctuations. It is usually

- higher during the day than in the night
- higher on a working day than at the weekend
- higher in winter than in summer
- higher in bad weather than in good weather.

Strongly temperature-dependent is especially the night area because of night storage heating, whose development has already led to considerable form alterations in the day-load curves. The night area of the day-load curves is therefore considered separately in order to show courses adjusted to allow for storage heating.

For the analysis of the main load a three-dimensional consideration is possible. If one arranges the curves of one type of day (e.g. a working day) within a coordinate system in such a way that the time (24 hours a day) appears on the X-axis, the years (52 weeks) on the y-axis and the load on the Z-axis, then one receives "load mountains". With a complete weather correction of the load, it is possible to work out the whole weather-conditioned spread of all loads and also design the form of the load mountains which would have occurred after many years' mean weather conditions (in particular temperature). The loads of these base-mountains are expediently referred to a reference load and thereby made relative.

The result is the load mountains from standardized (adjusted to allow for night storage heating) day-load curves (characteristics), which represent the load structure of the current past.

These load mountains represent a "form offer" for establishing the load models, where the aim is to arrive at a typical day-load curve for any desired number of weeks within a planning year.

The path to be taken includes a side view of the load mountains. From this perspective, the annual course of the load of selected times of day can be seen. This course is mainly shaped by seasons and therefore to a considerable extent more regular than that of a day characteristic.

If one succeeds in finding a mathematical function for the annual course, then the expenditure for data storage and processing for the formation of load models can be reduced considerably.

The current load observation has shown that the sine function

is a reliable model for the description of annual courses of most of the load points. (This used not to be the case.)

For the presentation of load mountains as a load model, one therefore only needs a typical winter characteristic and a typical summer characteristic. All others result from interpolation in accordance with the sine function.

If one defines a day-load curve with printings (hourly), then one has to determine in all 24 pairs of values (one value for winter, one for summer), which can serve as control data for the construction of base-load mountains. A chain of mountains has to be constructed for each of working days, Saturdays and Sundays.

In this way, a base-data file can be created which contains 3 x 52 = 156 standardized day characteristics.
The selected form of generation of the base-data file of an organically changing supply area is in itself very variable. Nevertheless, this method can be used to show a simple reaction to structural changes ascertained.

For the construction of the load model for one planning year, the load mountains from the base-data file are now made "pliable" so that they can be adjusted to planned structural changes with a few actuating variables, in the following way:

- the reference load leads to absolute values of the load in MW and fixes the winter load level. It is the value of the morning peak expected in the first week of the year on a working day on average (about zero degrees Celsius).

- the rate of growth increases the end of the year as against the beginning of the year.

- the energy generated annually and thus the sales directs the volume below the chains of load mountains and thus the duration of the employment of the reference load.

A desired reduction of the said duration, i.e. a decrease of the volume below the base mountains, leads to a relative deepening of the summer load level. Hence this can be used to change the annual course of the load as desired.

Extreme influences (e.g. the outside temperature) on the load courses of day-load curves (a few or all curves to be modelled) within a year can be established by the alteration of a temperature factor.

The night current for storage heating can be included in the day-load curves thus recorded. The energy generation per day curve is dependent on the expected annual sales

and the temperature. As the temperature dependency is specified, the value for the expected annual sales is sufficient as an additional control variable to determine the corresponding energy of one day. This, finally, is changed into additional night loads.

In order to further increase the flexibility of the load, provision has been made for the possibility of illustrating additional deliveries exceeding the load structure of the actual supply area. Via a night-day differentiation of the capacity, additional loads occur, which can additionally influence the form of the day-load curves. All load elements are added to the model day-load curve.

For the correct determination of the model day-load curves, there are data giving information on the weeks in which there are additional public holidays (load structure as with Sundays). For long-term planning, three representative characteristics are normally produced for a two weeks' period of time.

3. Load Model for the Generating of District Heating

As described for the generating of electricity, district heating load relationships, too, can be modelled with the aid of the computer.

The analysis of the first phase of model development permits the illustration of regularities with the load course as a result of the course of many years' mean day temperatures as well as the specification of the temperature dependency of the load. Whereas phase 1 ends with the presentation of base mountains from standardized day-load curves shown relative to other factors, phase 2 creates the load models in slices from the base mountains of the various types of days for the individual supply areas. In this way, nine district heating supply areas of HEW in all are represented.

4. District Heating Generating

In the model system developed for this, we have a computer-aided illustration of meeting the loads using the district heating load models. Models have to be created both of the heat network storage within island networks (industrial steam) and of grid networks (city heating with hot water and steam). The employment sequence of the plants participating in the grid is deduced from the heat price ratios. The extent of the employment is dependent on the delivery limits within the network, for which data has to be fed in.

A model has to be developed for each production plant and

has to represent the most important thermodynamic interrelationships, e.g. the dependency

- of the electrical back pressure on the thermal output
- of the flow of fuel on the useful output
- of the electrical output decrease on the thermal output in the case of extraction-condensation plants.

The electrical output decrease represents the relation with the model for current generating. It makes the still unused condensation output possible for additionally meeting electric energy demand.

5. Electricity Supply

The model system developed for this represents the use of all sources of power generating through the respective load model.

The plants of its own which an EVU can use to generate electricity can be dividedinto heating and power stations, condensation power stations (conventional and nuclear), gas turbine plants and pumped storage power stations. A model has to be developed for each plant group so that every plant can be illustrated.

When simulating what plants are to be used, one can distinguish between having of necessity to divide generating among the plants, free employment of plants and unavailability. Contractually agreed supplies have to be deducted in their fixed amounts and they decrease the freely employable capacity; the same applies to compulsory employment of plants resulting from agreements on fuel purchases. The back pressure output transferred from the model of district heating generating can also be given priority in use for meeting the load.

The output remaining after deduction of the compulsory generating division and the electrical back pressure output is subject to the "free" employment disposition, in which respect the plants determined as available are optimized according to the cost-increase procedure. The employment hierarchy is formed from the model data for power stations via the fuel prices for the individual plants.

Every unavailability of a power station changes the generating division and thus the fuel costs for generating electricity. For this reason, the downtimes (repair periods) also form part of the essential control data of the system. Analogous with this simulation, before planned outages, non-scheduled failures can also be "tested" in order to

understand the spectrum of possible effects.

6. Ease of Data Output and Use of Model

The flexibility of load models makes parameter studies possible with which the range of probable and indeed desirable developments can be examined. They can lead to statements on possible load-smoothing.

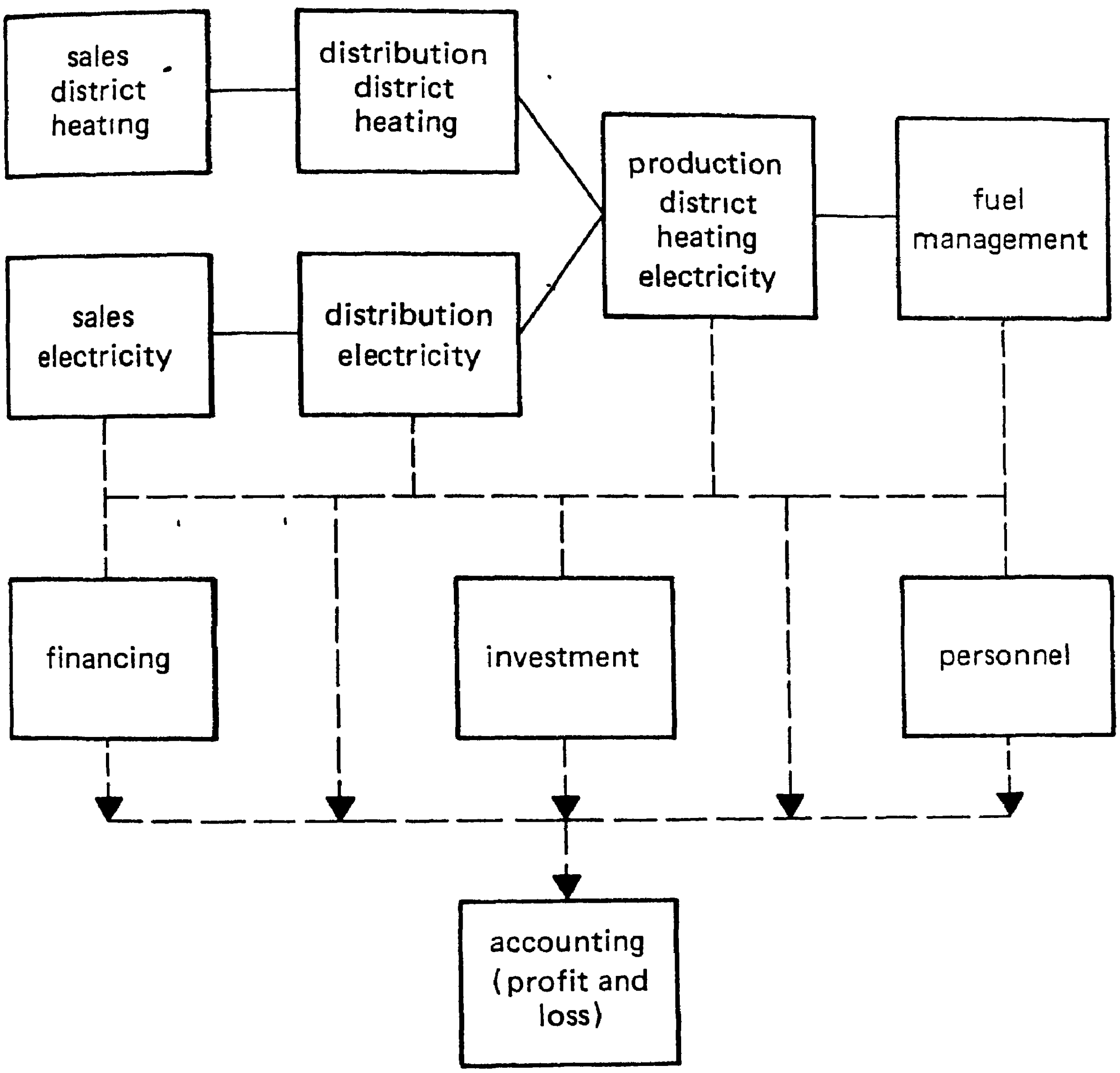
The possibility of independent modelling of the whole district heating generating through the district heating load models can be used for efficiency calculations for district heating and power-heat-coupling. The district heating generating plan can be drawn up with the aid of these models; it gives information on the utilization of the individual sources of production.

The ease of data output for electricity production makes a detailed and complete insight possible into the hierarchy of power station employment and into meeting the load. The form of the summary of annual results is the same as that of the day-summary. Separated according to sources of production, network storage and the use of fuels inter alia are shown. The individual annual results can be stored on a disk file if required. Thus a connected planning period of several years is to be stated and quoted. For instance a list, ready to take the form of a report, of the several years' plan for producing electricity and employing power stations, and of the plan for the fuel requirements (for electricity and district heating) can be issued in this way. The power station employment plan gives in particular all data for the development of the utilization of the individual production plants and is thus suitable inter alia for supporting investment decisions.

The fuel requirement plan gives an insight into the development of the fuel consumption structure. It shows direct the absolute and relative importance of the individual primary energy sources and their development, and gives the framework for fuels acquisition. The prognosis on emissions can moreover be made from the fuel consumption structure.

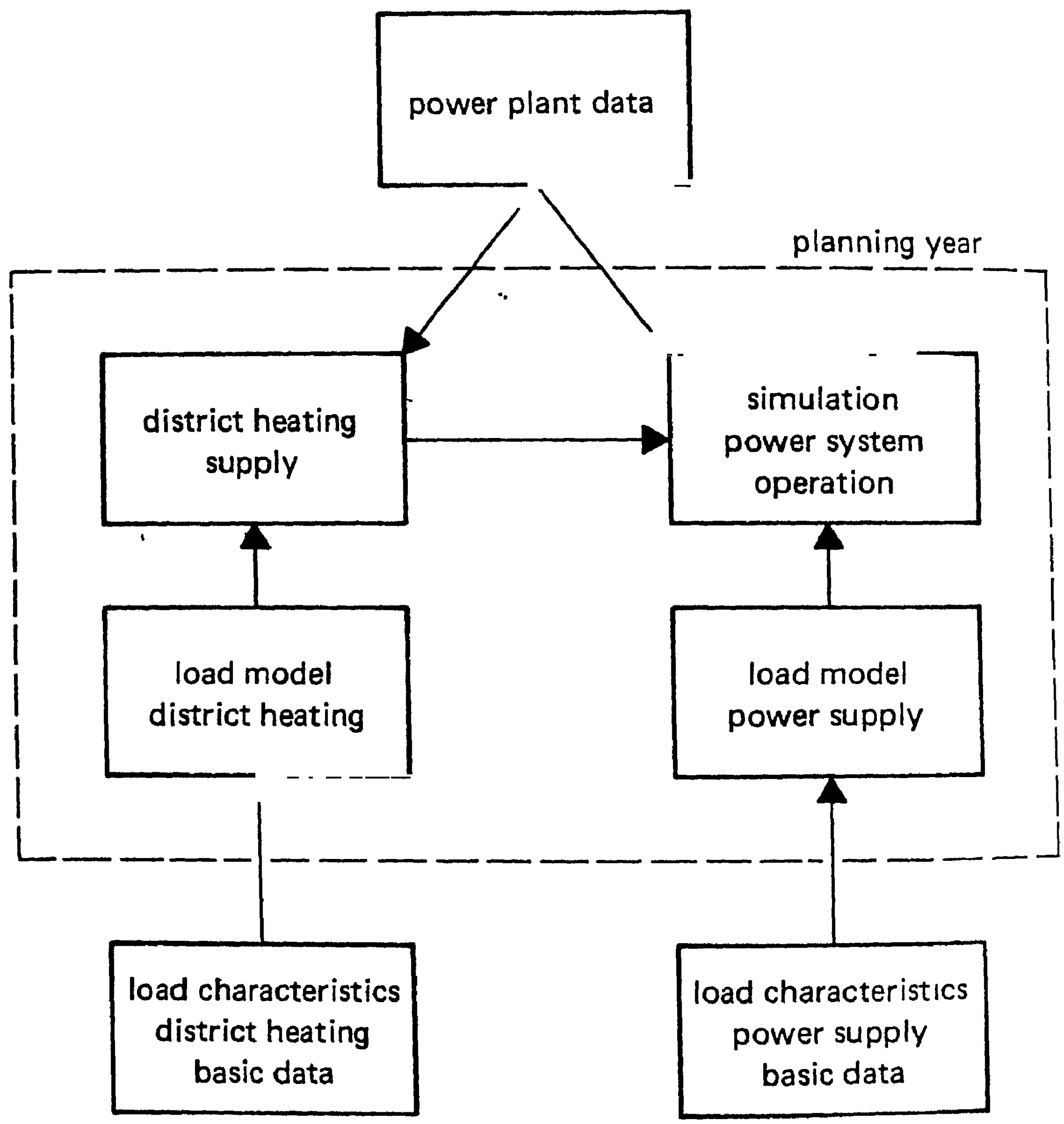
All this provides an instrument which can be used as part of larger enterprise models (production model) as well as added to operative planning activities (e.g. repair programs). The extent of the input and operating necessary is small compared with the comfort represented by the model.

Energy Production Planning using flexible Load Models



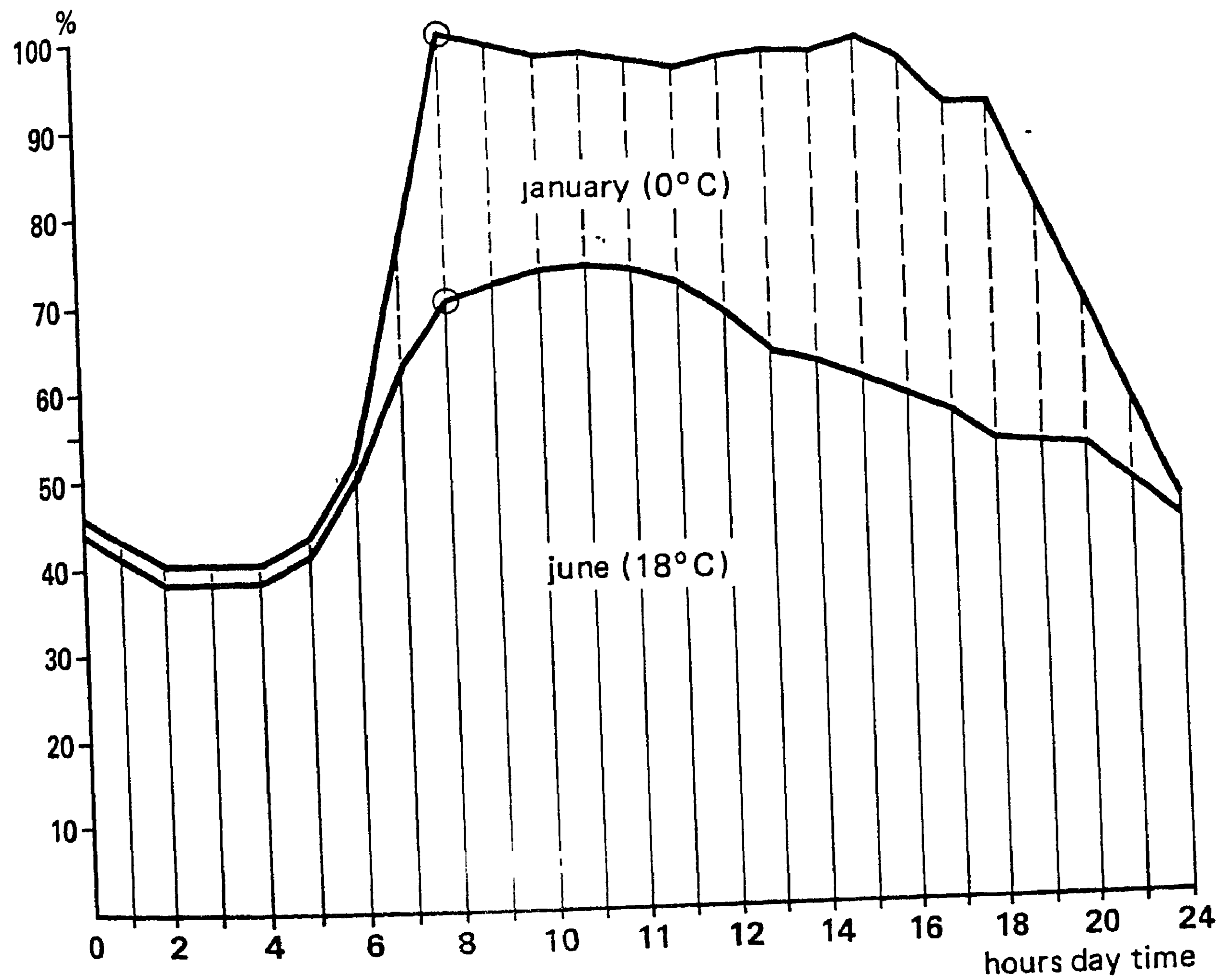
Functions to be planned in an Electric Utility

Energy Production Planning using flexible Load Models



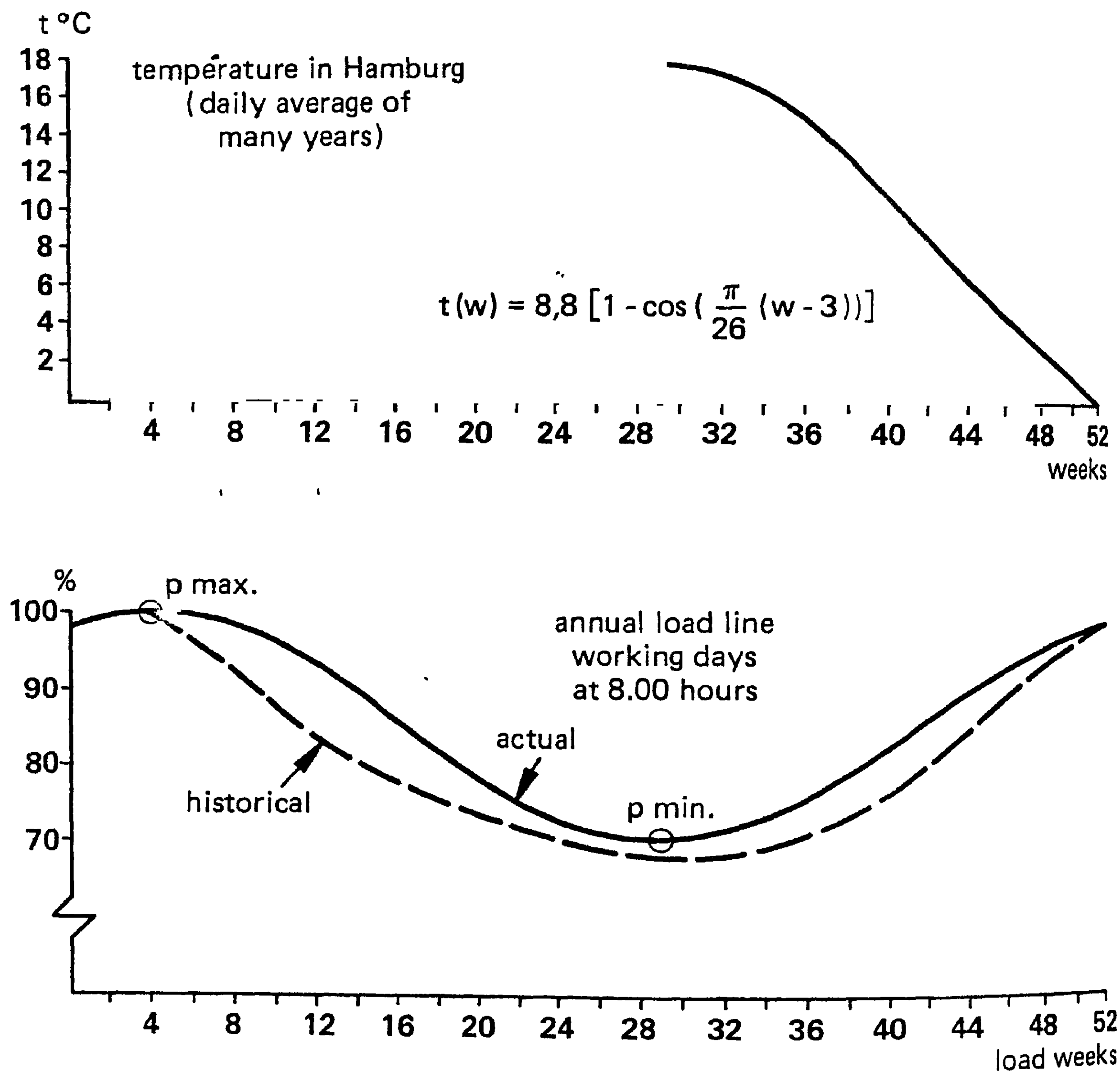
Models for Energy Production

Energy Production Planning using flexible Load Models



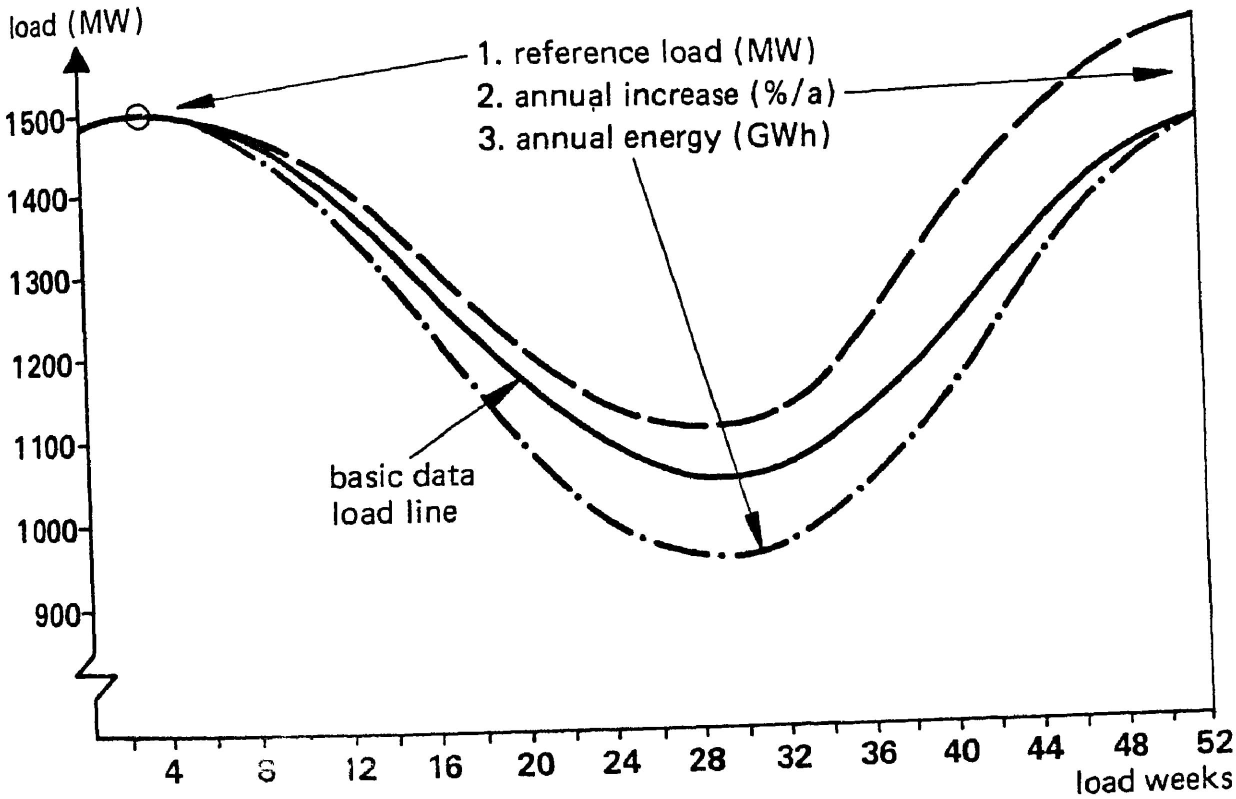
Normalized daily Load Curves
working days
(without night-tariff-heating)

Energy Production Planning using flexible Load Models



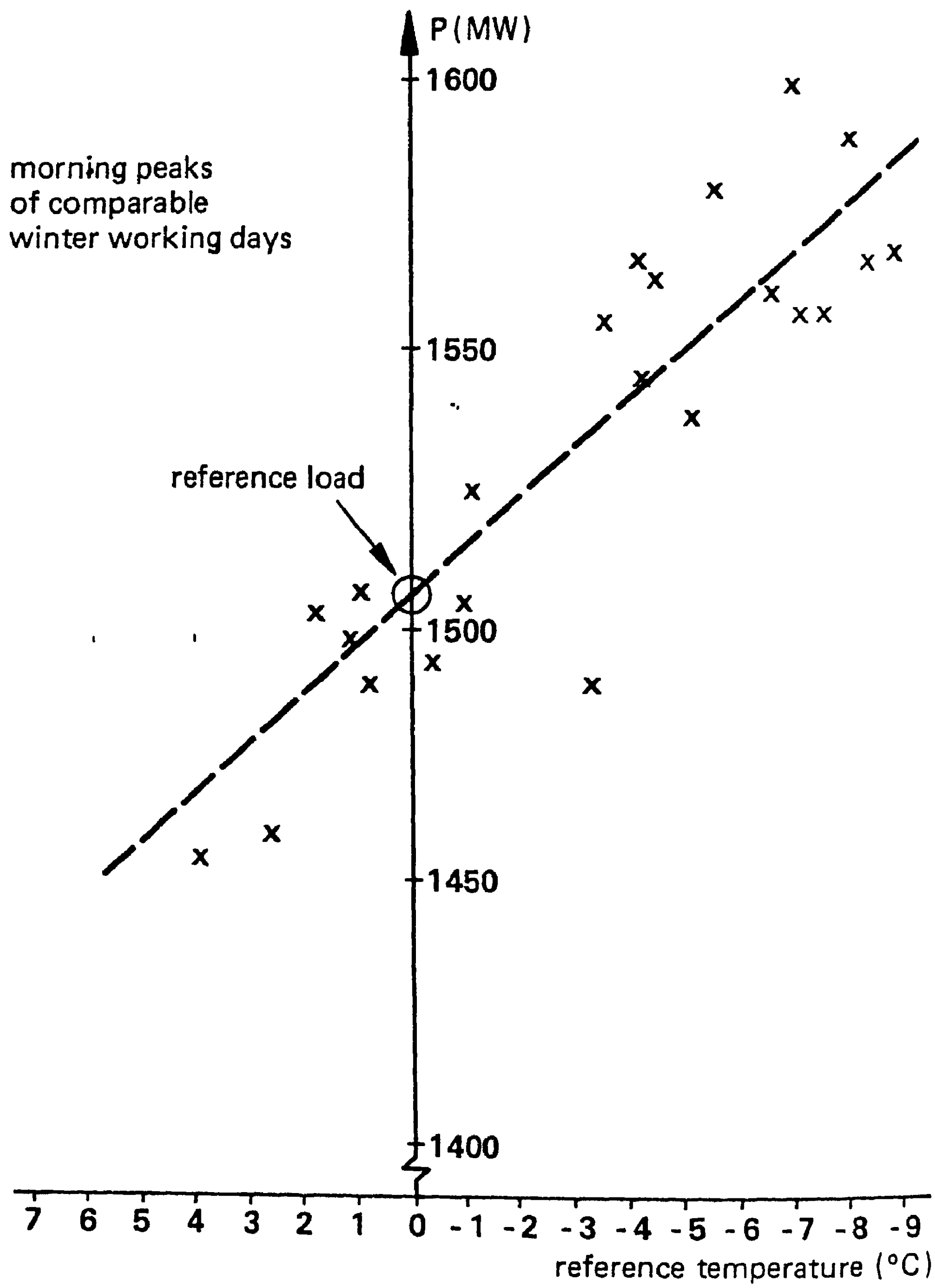
Seasonality of Temperature and Load

Energy Production Planning using flexible Load Models



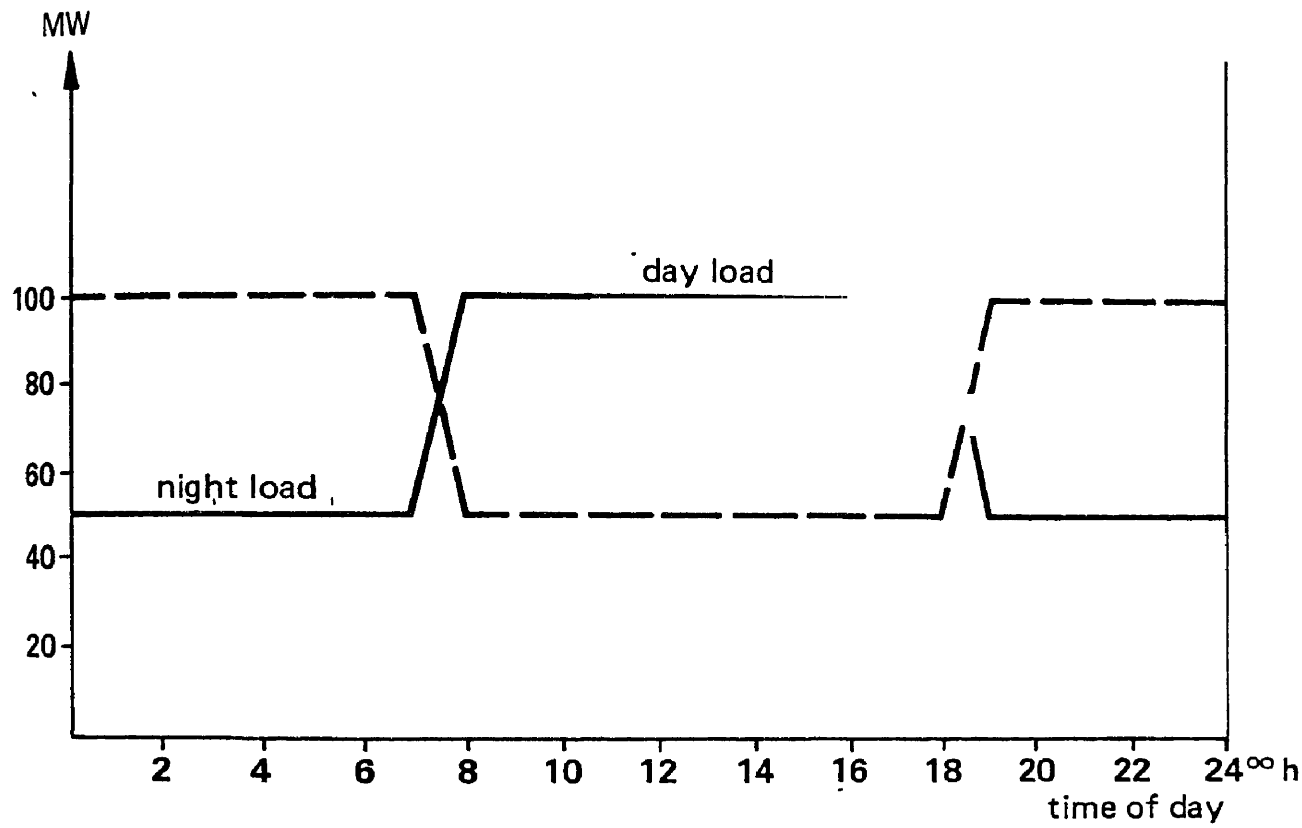
Control Data for the Load Model Construction

Energy Production Planning using flexible Load Models



Effect of Temperature on Load

Energy Production Planning using flexible Load Models

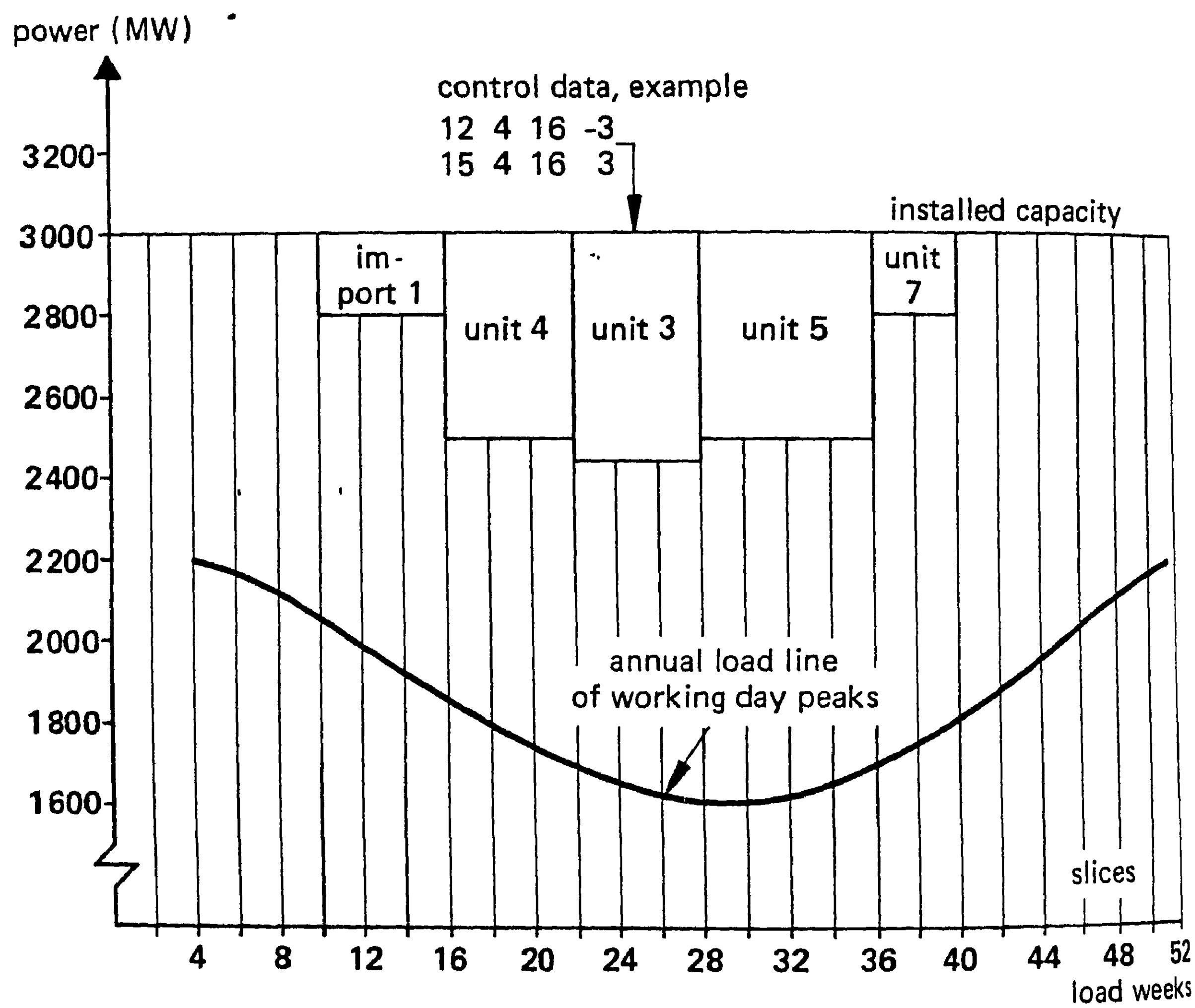


control data:

day load (MW)
night/day ratio
duration night time drop

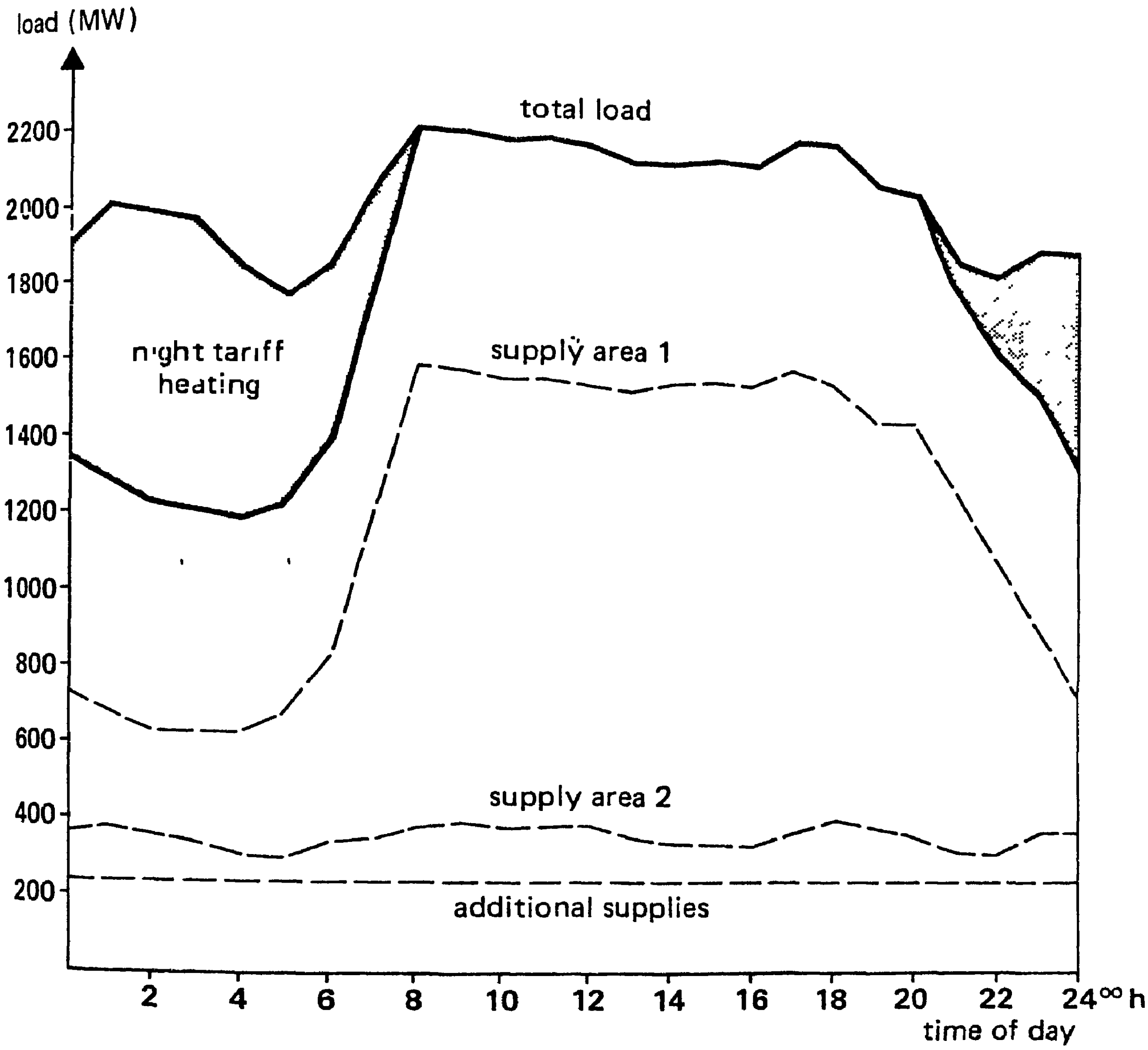
Modelling additional Supplies (Export of Energy)

Energy Production Planning using flexible Load Models



Repair-program, Non-availability

Energy Production Planning using flexible Load Models

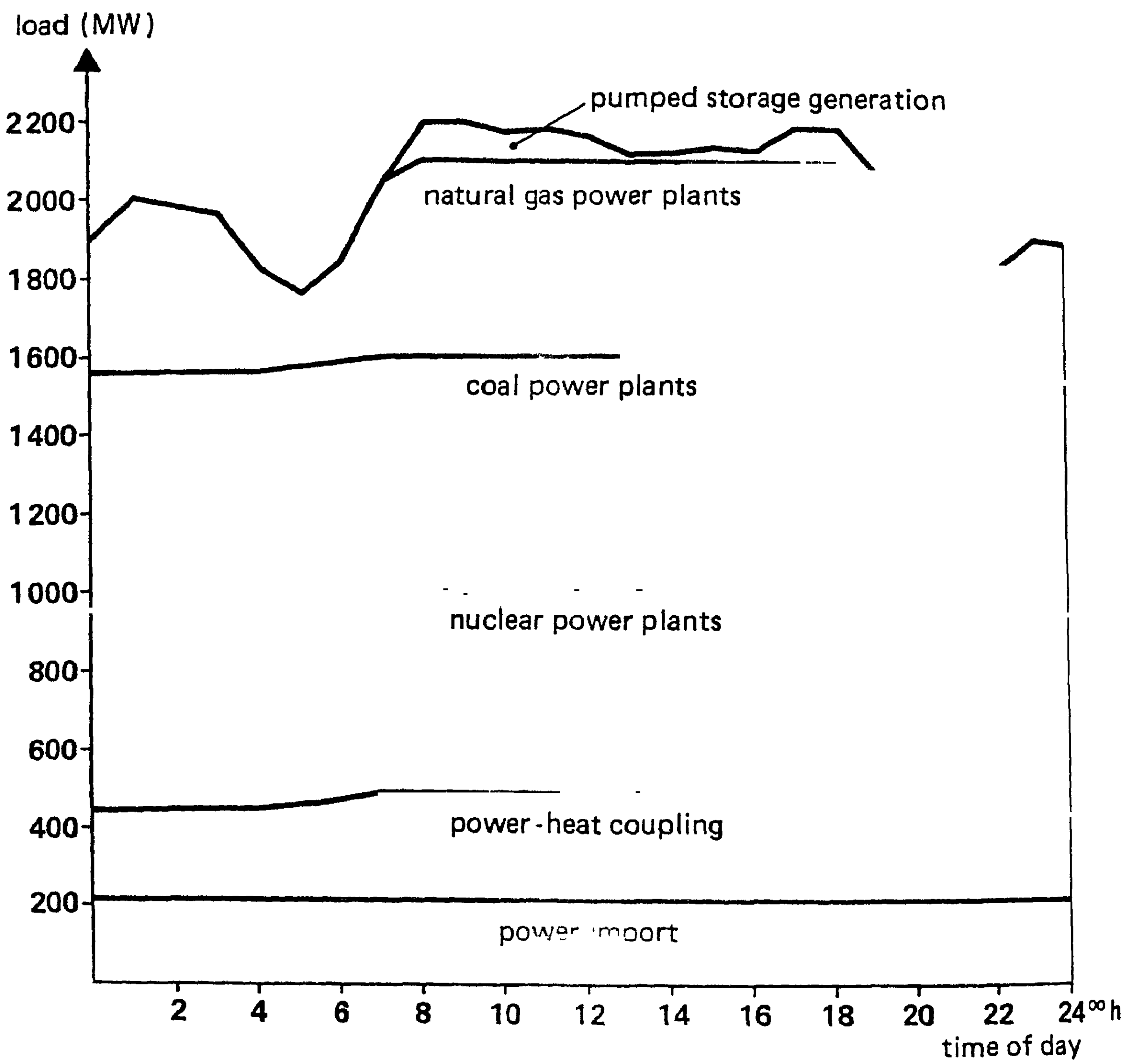


Model of a daily Load Curve

January — working day (2. week)

Temperature 0°C

Energy Production Planning
using flexible Load Models



Power Station running Simulation
using Model of daily Load Curve

In the early stages with the existence of small systems, the transmission system was restricted to radial lines connecting power stations to the load centres. After independence with the establishment of larger power stations, the State networks got integrated In the mid 60's with the concept of regional planning and optimisation, a beginning was made in the formation of regional grids in the five regions of the country.

2. Till mid 70s 220 kV was the highest transmission voltage which could handle the order of power that was to be transmitted over long distances.

3. With the formation of central generating companies and establishment of pit-head power stations, the need was felt for introducing 400 kV as the next higher transmission voltage. In fact, the first 400 kV line was introduced in 1977.

4. Next decision was to introduce HVDC Rihand - Delhi corridor for long distance point - to-point transmission of bulk power. Back to back DC link has also been introduced between Vindyachal and Rihand.

5. The HVDC facilities are at an advanced stage of completion and are likely to be commissioned in the next year or so.

6. Capacity of Transmission:

6.1 In general a 220 kV line can transmit 150 - 200 MW power over 100 - 200 Km. 400 kV line can transmit 400 - 500 MW over 300 - 500 Km.

7. Power System Development

7.1 Transmission planning is now being attempted on a regional basis irrespective of State boundaries. This is being done on a long-term basis with appropriate phasing of implementation of the various facilities.

7.2 The power system development

process involving a number of system elements right from the sending end substation through the transmission line to the receiving end substation followed by down stream networks. The performance of each system element which comprises the transmission system as a whole determines the quality and reliability of power supply. In order to optimise the system, a fully integrated system has to be studied irrespective of ownership and appropriate agencies identified for executing the subsets of the total scheme.

7.3 Central sector shares get delivered to the beneficiaries in each region by displacement on net interchange principle.

8. Concept of system planning

8.1 Generally the 220 kV and 400 kV lines cut accross State boundaries whereas the lines 132 kV and below are confined to the States. In the regional planning, the exercises carried out cover individual State requirements as well as inter-State and inter-Regional power transfers, emergency exchanges between States, surplus inter-Regional power transfers, consolidation of regional level operation with a view to eventual formation of national grid.

8.2 The planning exercises take into account the latest technological developments, environmental aspects and right of way problems, HVDC options and introduction of 800 kV class voltage versus series compensation.

9. TIME FRAME FOR PLANNING

The long term and medium term planning should take note that it may take 5 to 7 years or more for implementation of each EHV project. To avoid premature redundancies long and medium term studies should be carried out simultaneously. The studies should be based on assumpsions on the following :

1. Generation

2. load - active and reactive

3. Reactive compensation

4. Resource constraints.

Because of frequent changes in generation and load forecast, changes are called for in the transmission network. Therefore, planning studies should be done on a continuous basis.

9.2 At the State level, one can look at short gestation period for the State transmission system, keeping in view the regional system development, inter-related regional exercises, etc.

10. <u>Constraints in implementation</u>

10.1. Of late there have been many inadequancies in the implementation of T&D programmes. These inadequacies can be traced to the following reasons :

- Inadequacy of investments in T&D works
- Problems in obtaining Forest clearance for construction of transmission lines
- Problems of obtaining right of way (ROW) through agricultural land
- Problems of execution
- Problems of multiple ownership and sharing of transmission cost.

10.2 The executing agencies are mainly SEBs, NTPC, NHPC etc. CEA monitors closely the implementation of EHV transmission projects.

11. <u>Planning Criteria</u>

11.1 The planning criteria take into account the following :

- Load power factor
- Generation

    Scheduled maintenance

    Auxiliary consumption

    Partial voltage

Forced outages

Spinning reserve

- Generation despatches

  Peak load

  Minimum load

- Steady - state line loadings

  Voltage limits

  Fault levels.

12. PROGRAMME

12.1 The following programmes have been acquired by CEA to carry out the system studies :

Power flow

Short circuit

Transient stability

Reliability assessment

Economic analysis.

EMTP

13. UTILITY SOFTWARE

13.1 Single line diagram

Swing curve plotting

The above programmes are very versatile and permit modification of network through inter reactive VDU terminal linked to the main computer system. This makes studies of various alternatives easy before the chosen network emerges which can be quickly plotted through the graphic unit.

14. EMTP

14.1 This programme is used to quantify high frequency switching over voltages and power frequency dynamic over voltages under certain conditions of system operation to facilitate determination of the required specifications for shunt reactors and circuit breaker, switching resistors

15. Long-term perspective transmission plan up to 2000 AD

15.1 Based on scenario approach corresponding to the various conditions of load and generation optimised regional network for each region has been developed by the CEA up to the year 2000 AD after considering all the extra high voltage i.e. AC, HVDC options. For doing this, the various studies have been carried out as detailed above. The results of these have been summarised in 8 volumes covering each of the various regions. For the first time an all-India power system study was also attempted for export of power between the regions either on continuous basis or during the lean periods. These exports inter-regional mainly involve power from the north-eastern and eastern regions to the northern region, as also the southern region either directly or through the western region. The studies have identified the required inter-regional link which will enable flow over the regional transmission system already developed and tested as per the above mentioned studies.

16. Load despatch and communication facilities:

16.1 It is also necessary to introduce appropriate and reliable communication, data acquisition and control system before operation of the regional grids and all India grid is attempted with highly sophisticated equipment at the various generating stations and substations. There is, therefore, an imperative need to introduce modern electronic and digital equipment both in the communication and load despatch fields.

16.2 Keeping all these in view a rough estimate has been prepared which shows that as per the CEA studies an investment of the order of Rs. 950 crores would be required during the 8th Plan period for

inter-regional facilities alone including load despatch and communication. The same would be Rs. 1350 crores for 9th Plan. The requirement of funds during the 8th Plan for the inter-regional, regional and underlying T&D xxx network would be of the order of Rs. 31950 crores and the same for the 9th Plan would be Rs. 36,350 crores.

Integrated operation of power system

1.1 A regional approach to power planning was adopted in the country in the mid sixties. Since then planning for generation capacity additions and power systems development have proceeded on the assumption that power systems in each region would operate in close integration and power would be exchanged between systems conforming to well established principles. Facility to enable integrated operation of power systems both in terms of transmission facility and to some extent communication and control systems have also been established. Effective integrated operation of the regional grid systems has become all the more important with the increasing participation of central generation in the different regions. However, progress of inter connected operation and the evolution of the grid system has not been altogether satisfactory in the different regions. The management of the regional grid systems is faced with a number of challenges, some of which are unique to the conditions prevailing in the country.

1.2 The pre-requisites for smooth regional operation are:-

- A well planned transmission network with adequate redundancies.
- Reactive comepnsation facilities of the requisite type.
- Flexibility in generation scheduling and improved plant availability.

Contd.....2....

voltage within the permissible limits. In earlier times with only radial power systems there was not much difficulty in ensuring load and generation balance but with wide spread generating stations and transmission networks, technical limits on the source of energy (water availability, commitments for irrigation discharges, storage without spill over, uncertain nature of thermal power plants, lack of spinning reserve, etc) the task of maintaining appropriate quality of supply has become very complex. The ultimate aim should be not only to ensure a proper quality of supply but also to deliver power to the consumer at the cheapest cost. These aspects have all these years been engaging the attention of the power engineers but with the introduction of digital electronics into the power sector in recent times in the form of sophisticated electronic equipment such as computers, sophisticated software, data acquisition systems,microwave / optical fibre / satellite communication media, there has been rapid advance in the art of system operation and control especially in the area of SCADA in the load despatch. A beginning has also been made in our country in this direction.

2.2 In this presentation the emphasis would be more on the features of load despatch centres and the progress that has been made in our country thus far.

3. Functions and facilities of a load despatch centre

3.1 Functions

- Operation, planning, load forecast, generation scheduling, reserve allocation, scheduling of exchange, etc.
- Continuous monitoring of the dynamic power system conditions and initiation of appropriate control strategies.

- Post-despatching activities like post-mortem analysis of disturbances, generation of reports, etc.

3.2 Facilities

- Real-time data acquisition, data processing and telecontrol facilities.
- Computational facilities for carrying out predictive, real-time, extended real time and post mortem studies.
- Versatile man-machine interation system including operator's consoles, colour graphic/semi-graphic VDUs, MIMIC Board, recorders, etc.
- Communication system for speech, telemetering, teleprinting, telesignalling, facsimile, etc.
- Uninterruptible power supply
- Air conditioning.

4. Typical hierarical set up of load despatch centres in the country comprises the following tiers

National level

Regional level

State level

Sub despatch centre for certain areas within large States

Acquisition of data through RTUs / transducers from various substations and power stations at data concentrators.

Real time features and functions already implemented at various control centres are briefly summarised below :

- Hierarchical structure consisting of several levels of computer systems
- Dual real time processors or multiprocessors plus redundant peripherals
- High speed, digital telemetry and data acquisition system
- System wide instrumentation of electrical quantities and device status
- Colour CRT's with graphics for interactive display.
- Dynamic wall Board group display

- Automatic generation control
- Economic despatch calculation
- Automatic voltage (VAR) control
- Supervisory control (Breakers, capacitors, transformer taps, generating units, start up and shunt-down).
- Security monitoring
- State estimation
- On-line load flow
- Steady State security analysis
- Optimum power flows
- On-line short circuit calculations
- Automatic system trouble analysis
- Emergency control, automatic load shedding, generator shedding, line trapping.
- Automatic circuit restoration

5. ADVANCED POWER SYSTEM FUNCTIONS

5.1 There are also what are known as advanced system functions where the errors in the data acquired are detected, bad data rejected, appropriate value substituted for missing measurands, etc so that a reliable data base emerges. This would lead to ultimately contingency evaluation for N-1 con-dtions on a continuous basis (based on real time acquired, the system security is evaluated by load flow anslysis, Certain specified elements like a major transmission line, transformer or any other system element pre-selected is assumed to go out of commission and one at a time (N-1) in such a situation, the system is tested to ensure whether the remaining elements can handle the power flows etc without any security limits being violated. This analysis enables

the operator to take anticipatory action and avoid sudden black outs or grid disturbances due to failure of major system elements in real time operation).

5.2 Similarly, real time generation despatch could cover economic despatch to take into account the real time cost of generation, cost of transmission etc. so that power delivered at any given time is generated and transmitted at the lowest cost.

5.3 Automatic generation control, automatic switching, etc. are also additional features in real time functions. Equally important is the upgradation of software manpower management through training etc.

5.4 It is desirable to include the following features also in the computer system for load despatch centres :

- Real-time systems with emergy management software
- Versatile MMI with graphic facilities
- Microprocessor based RTUs
- Compatability and upgradability :

  The system should not pose problems in interfacing with the existing equipment/ systems or in upgradation

- Data base management system (DBMS) facilities

  A powerful DBMS is preferred as it would facilitate flexible software expansion and maintenance.

- Computer - computer links :

  Such links are preferred over conventional telemetery links for data exchange between different levels of load despatch centres in an heirarchy

- Use of High level languages:

  Capability for performing real-time progrsmming in high level language would greatly help software development work.

6. FUNCTIONS OF RTUs

6.1 The remote terminal units which are essentially meant for data acquisition and to work as slaves for Master station should have capability to handle the following :

- Data acquisition (measurands, status and alarms)
- Transmission of acquired data to master station
- Handling of communication protocols
- Execution of control commands/set points received from Master stations
- Local processing like limit checking and alarming (optional)
- Display and logging (optional)
- Sequential event recording (optional)
- Under frequency load shedding (optional)

7. COMPUTER ARCHITECTURE

7.1 Generally there is a dual computer system in the load despatch centres so that if one system is not working it functions can be taken over by the second system. These are sometimes assisted by front-end computers which acquire and preprocess the data before feeding it into the main computer system. There will be test and training computer system.on which training functions can be carried out in an environment replicating the computer centre. On the same system testing and upgradation of software can be carried out.

7.2 The introduction of microwave based telematry with intelligent terminals has made possible certain pre-processing functions, energy management functions, etc. being carried out at remotes thus leaving free the main computer system for essential and advance level functions. The software can be

made responsive to the actual needs of the despatch centre by display of tie-line flow. Summation of energy despatches, monitoring the limits etc. so that the despatcher's time need not be spent in routine work. He can devote his time to more important functions such as grid security etc.

8. ENVIRONMENTAL PLANNING

8.1 Apart from main computer centre, there are a number of other ancillary equipments needed to make the despatch centres functional. These are briefly mentioned below:

Space and labout requirements

Structural requirements (Floor, ceiling acoustic, etc.)

Environmental requirements (Humidity, air, temperature, etc.)

Power Requirements (V, HZ, Harmonics, lighting, etc).

Uninterruptible power supply

Fire protection and extinguishing system.

9. TELECOMMUNICATION FACILITIES

9.1 Telecommunication facilities are rapidly growing with new technology. The main media for telecommunication in the power system are as follows:

PLCC

Leased or dedicated telecommunication systems comprising the following media :

Coaxial

Microwave

Optical Fibre

Satellite communication

9.2 Communication requirements in the power sector are

to carry the following functions:

- Inter-trip facility to TRIP or block circuit breakers for quick isolation of fault.
- Speech and data transmission for system operation, monitoring and control.
- Exchange of operational data for generation of statistics, Reports and management information system (MIS).

9.3 In general the PLCC is being used as a most reliable system for item (1) above. For the remaining functions, with the rapid expansion of power systems, PLCC is inadequate and is being replaced through optical fibre, microwave, satellite etc.

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POLICY OPTIONS IN RURAL ELECTRIFICATION IN INDIA
With Special Reference to Pumpset Energization

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Abstract Over the years, the rural electrification programme in India has largely involved the development of irrigation pumps and tubewells The emphasis on energization of electric pumps, combined with a low tariff for supply of electricity to such pumps, has led to sub-optimal choices in this sector The distinction between private and social costs of energy supply for irrigation pumps, often becomes crucial in this regard The consideration of economically viable alternatives in the pumpset energization programme becomes especially important in the light of the power shortages in the Indian economy

INTRODUCTION

Only 0 5 per cent of the 576,126 villages in India had access to electricity in December 1951, but the progress of rural electrification accelerated after the 1960s, reaching 56 per cent of the villages in December 1983, from a figure of 8 per cent in 1966 [1] There was a quantum jump in progress after the drought period of 1965-67, which also coincided with the introduction of the high yielding varieties of wheat and paddy in Indian agriculture The significant feature of these foodgrain varieties was their dependence on assured irrigation, coupled with very good returns from such irrigation Simultaneously, the government policy also laid emphasis on electrification of pumpsets/tubewells (i e water lifting devices utilizing groundwater for irrigation), the development of other categories of rural electricity consumption being a secondary objective

The theme of this paper is the rapid increase in the category of electric pumpsets/tubewells compared to other consumption categories such as industry, domestic, etc , which also has implications for electricity and overall energy planning in the economy This paper also discusses the manner in which the present rural electrification programme has been undertaken and the need for a serious review to ensure that the energy needs of rural consumers (including irrigation) are met at the lowest cost to the economy as a whole

GROWTH OF ELECTRIC PUMPSETS

The most important category of rural electricity consumption is electrically driven pumpsets The connected load (kW) in agriculture is nearly 66 per cent of the total rural load, whereas the connected load in the domestic sector is only 15 2 per cent, that of rural industry 14 3 per cent, commercial 2 6 per cent, and street lighting 0 8 per cent Electric pumpsets also account for 64 per cent of the total rural energy consumption, whereas the other categories account for less than 15 per cent each (Government of India, 1982). The growth of electrically driven pumpsets during the period 1953-1983 has been quite impressive, ranging from 39,000 in 1953 to 51,38,000 in 1983

There are a number of reasons for the use of rapid growth in electrically-driven pumpsets for irrigation

1 There are considerable reserves of ground water still available in many parts of the country (Charlu and Dutt, 1982)

2 While dependence on canal irrigation implies corresponding dependence on an external source, viz the government agency operating the canals,

an electrical pumpset is directly within the control of the farmer, and literally available on tap [2]

3 The emergence of high yielding varieties has increased the importance of assured irrigation at the right time, and also increased the returns to the farmer, thus making the capital investment worthwhile

4 The low electricity tariffs offered by almost all the state utilities has further accelerated the growth of electrical pumpsets [3]

5 Government-supported financial agencies have also been giving liberal loan assistance for the installation of pumpsets

POOR FINANCIAL RETURNS

The rural electrification programme in particular led to the state electric utilities suffering considerable financial losses over the years The average cost of power at the low tension consumer end was more than 40 paise per kilowatt hour in most of the states, but the overall agricultural tariff was mostly between 10 and 22 paise per kilowatt hour[4] (Planning Commission, 1980)

It may be noted here that many state utilities have a system of agricultural tariff based on 'flat rate' In this system, the tariff is charged on the basis of a fixed rate per horsepower of connected load of the electrical pumpset, irrespective of the actual energy consumption during the year It is obvious that in this system the marginal cost of electricity usage by the pumpset to the farmer is nil Random checks by the utilities in several states are stated to have revealed that consumption per pumpset has increased in the past few years with the flat rate in force [5]

An attempt was made by the authors to estimate the quantum of subsidy on account of the low agricultural pumpset tariffs (Table 1)

It may be mentioned that the subsidies have been calculated on the basis of 'average' costs at the rural distribution point, these average costs include capital and operating costs All Long Range Marginal Cost (LRMC) estimates are much higher than the above average costs and hence the subsidies would be higher if LRMC is

Table 1 Statewise subsidy on agricultural tariffs

State	Electricity consumption in agricultural sector (GWH) 1981-82	Tariff paise/kWh	Average cost paise/kWh	Estimated subsidy in rupees million
Haryana	1159 40	31	34 74	43 4
Punjab	1860 07	13	53 73	757 6
Rajasthan	1031 28	21	67 09	475 3
Uttar Pradesh	2833 24	28	81 07	1503 6
Gujarat	1316 23	33	48 65	206 0
Madhya Pradesh	393 82	25	71 95	184 9
Maharashtra	1878 74	30	55 93	487 3
Bihar	493 73	7	74 99	335 7
Orissa	64 19	18	83 24	41 8
West Bengal	66 32	35	71 00	23 9
Karnataka	427 15	22	41 38	82 8
Andhra Pradesh	1004 55	20	58 85	390 3
Kerala	105 04	13	66 55	56 3
Tamil Nadu	2475 73	16	57 29	1022 3
				5611 2

Source CEA and Report of the Committee on Power (1980) The cost figures are computed from the figures given in Table 5 6 of the report of the Committee on Power, which have been suitably adjusted for inflation

considered If LRMC estimates are used, the estimated subsidies would be much higher

The total subsidy as given in Table 1 is Rs 5611 million It is interesting in this context to note that the total financial losses of all the above mentioned state electric utilities in 1981-82, were Rs 1109 40 million It is clear that, but for the subsidised agricultural tariff, the electric utilities could have had a respectable net surplus

COMPARISON WITH SOME OTHER ASIAN COUNTRIES

Table 2 shows details of electrically driven irrigation connections in five Asian countries including India

Both on the basis of population and area, the progress of electric irrigation pumping in India has been far ahead of the other countries Bangladesh and Pakistan are somewhat similar to India in climate and general economic condition, and India's emphasis on electrical pumping is much greater than that of these two countries India's path of rural electrification is thus significantly different from other developing Asian countries as it lays tremendous emphasis on electrically driven irrigation pumps [6]

IMPLICATIONS OF PUMPSET ELECTRIFICATION PROGRAMME

Pumpset load has several special features, with implications for the power system as a whole, which are discussed below

1 As the load is irrigation-based, it is generally seasonal The seasonal factors have very important effects on power system planning and operations Hydro-generation, for instance, is affected by seasonal factors (Harberger and Andreatta 1964). During the rainy season, the requirements of electricity for irrigation go down substantially, with resultant effects on total system demand In this situation, a delay or failure of the monsoon will have an adverse affect on hydro-generation, simultaneously increasing the demand from irrigation pumpsets

2 Apart from its seasonal character, and partly because of it, the pumpset demand in most states is characterized by a very low annual load factor (Table 3) [7]

Table 3 Statewise Annual Load Factor for Pumpsets

State	Average annual working hours	Load factor (%)
Bihar	1079	12 3
M P	423	4 8
Karnataka	382	4 3
Kerala	362	4 1
Orissa	784	8 9
Andhra Pradesh	543	6 1
Gujarat	791	9 0
Maharashtra	786	8 9
Rajasthan	935	10 6
Tamil Nadu	789	9 0
U P	1385	15 8
Haryana	1063	12 1
Punjab	1674	19 1

Source Central Electricity Authority, *Public Electricity Supply Statistics*, 1981-82, New Delhi

The low load factor, taken together with the high

Table 2 Comparison with Other Asian Countries

Country	Year	No of pumps	Pumps per 1000 sq km	Pumps per million population
Bangladesh	1983	9200	63 88	129 01
India	1983	5130000	1619 91	7502 08
Pakistan	1982	76397	95 02	911 08
Philippines	1981	750	2 50	15 63
Thailand	1982	375	1 891	8 30

Source First two columns from Asian Development Bank, Rural Electrification Survey, Draft Report, Manila, 1983, last two columns calculated on the basis of population and area figures from *Statesman Year Book*, New Delhi, 1983

seasonal variation, has important implications for the power system, as the generation and distribution capacity required for meeting this type of load, would be higher than that required for meeting a reasonably uniform load throughout the year.

3 Besides seasonal variation and low load factors, the pumpset load is also a scattered one These low-voltage loads add considerably to distribution costs as well as system losses

4 The rural network, in most state systems, has grown in a haphazard and unsystematic manner (Sengupta, 1984) An important feature of the rapid growth of pumping loads has been the increased unreliability of power supply to the rest of the system, mainly industry Once pumping load have been sanctioned and connected, it is obvious that agriculture is vitally dependent on irrigation being available when required If there is a delayed monsoon (or even a failure of the monsoon in some parts of the country) the excessive use of pumps for a longer period results in a shortage of power in the economy as a whole. Under such circumstances, it has been a common experience in many states in India (especially states with a large number of electric pumpsets such as UP, Haryana, Punjab and Tamilnadu) that electricity supply to the industrial sector has to be curtailed by physical controls, such as load shedding or power cuts.[9] This point will be discussed later in this paper

LOAD GROWTH PATTERN IN RURAL ELECTRIFICATION PROJECTS

The Rural Electrification Corporation (REC) is a central government agency advancing long-term loans to state electric utilities for specific rural electrification projects The REC now finances more than two-thirds of all rural electrification works in the country

In most REC-financed projects, the projected load growth is targeted to be attained progressively over a period of five years To study the recent patterns of load growth, 19 schemes were selected at random from a total of 302 sanctioned by REC in 1974-75 throughout the country Details of anticipated load growth and actual achievements in respect of each consumer category were collected for each of these projects Nine of these projects were in areas classified by the REC as 'advanced' and the remaining ten in 'backward' areas [10]

The load development achieved up to 1980-81 is given in Fig 1 It can be seen in the figure that, except for one scheme in Karnataka, Andhra Pradesh and Orissa respectively, the percentage share of pumpsets in the total connected load has been above 65 per cent in all the schemes In 11 of the schemes, the percentage share has been above 70 per cent If all the samples are taken as a whole, the percentage share of pumpsets is 75 63 per cent It is observed that the larger states, such as Maharashtra, Madhya Pradesh, Uttar Pradesh, Tamil Nadu, etc , have registered a very rapid growth in pumpsets compared to other types of connections

The share of pumpsets in the connected load is over 75 per cent in the sample schemes, as against 66 per cent in the existing mix of rural loads, thus reinforcing our earlier point regarding the increasing trend of pumpset electrification

ECONOMICS OF ALTERNATIVE PUMPING TECHNOLOGIES

There is growing evidence that electricity is not the least-cost motive power for meeting irrigation requirements of farmers A recent paper discussed the impact of rural electrification on agriculture and concluded that, apart from a significant impact on agriculture, there is no major effect on other consumers in rural India (Barnes, 1985) The comparative costs of alternative individual irrigation systems have naturally varied from time to time, depending on the prevalent prices of light diesel oil, electricity, etc

In alternative pumping technologies, the pump remains more or less the same, while the motive power for running the motor is derived from different sources These sources include solar photovoltaics, biogas, windmills and gasifiers, apart from the two common sources used in rural India, i e electric and diesel

Bhatia (1980, 1984)[11] has recently estimated the capital and operating costs of different irrigation systems These costs are estimated from the point of view of society, using appropriate shadow prices for labour and foreign exchange inputs The present value of the sum of the capital and operating costs at an appropriate social discount rate are compared For a farm size of 1 ha having a head of 5 m water depth and for crop rotation of wheat and rice, the ranks (lowest social costs, having the rank I) for the

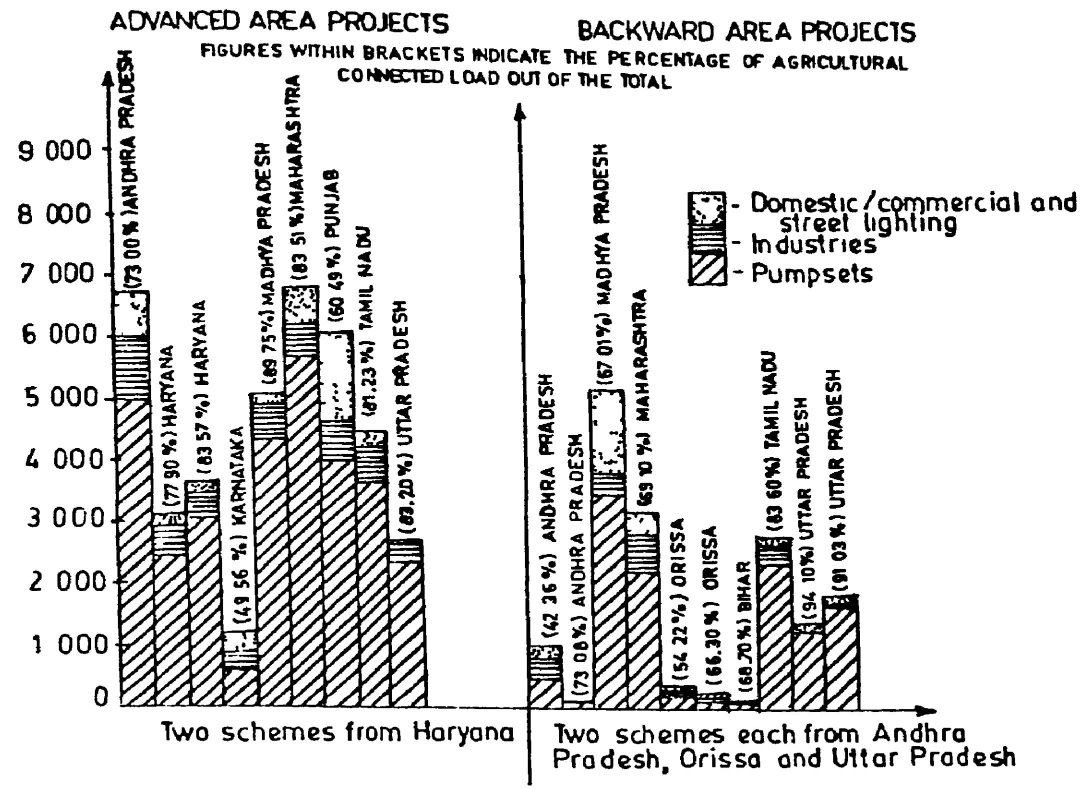

Figure 1 Load development achieved up to 1980-81
(Computations by authors)

different technologies are indicated in Table 4 It is important to note that except 100 per cent diesel-operated and 100 per cent electrically operated pumps, other technologies are still not fully developed for commercial applications

Table 4 Comparison of Alternative Irrigation Technologies

S No	Technology	Rank (Social costs)
1	Electricity	III
2	Diesel oil	II
3	Biogas and Diesel	I
4	Producer gas and diesel	IV
5	Solar photovoltaics	VI
6	Solar thermal	VII
7	Wind mills	V

In Bhatia's two papers, while the electric pumpset is the cheapest alternative when evaluated at market price, it is no longer so when evaluated at social costs In the earlier paper, the biogas (100 per cent) with petrol engine is the cheapest at social cost, but this position is taken by the diesel plus biogas bi-fuel system (closely followed by the 100 per cent diesel operated system) as shown in Table 4 It is interesting to see that, whereas the costs of other systems do not change much when evaluated at social costs, the costs of the electrically operated system go up by several times The major reasons for this are

1 The operating (or energy) costs are not recovered by the agricultural tariff

2 A part of the capital costs of generation and transmission are attributable to the RE loads, though the RE consumer does not bear any part of it

A COMPARISON OF ELECTRIC AND DIESEL PUMPSETS

An attempt has been made to make a comparative cost analysis of electrical and diesel-operated

pumps, both of which are widely used by the Indian farmers As the average size of the electrical pumpset used in the country is about 5 hp (i e 3 75 kW), the costs of a 5 hp electrical pumpset have been compared with a 7 hp diesel pumpset, as the energy available at the shaft of a 5 hp electric motor is equal to the energy available at the shaft of a 7 hp diesel engine [12] The energy available at the shaft, in turn, provides power for running the irrigation pump. A 5 hp electric pumpset and a 7 hp diesel pumpset, therefore, provide an equivalent water output for a given pump and a given head (and other similar conditions)

The comparison has been made both on the basis of private (market) as well as social (shadow) prices/costs.

As far as private costs (market prices) of an electric pumpset are concerned, the farmer does not have to pay anything apart from the cost of the pumpset itself, the pumphouse and the highly subsidised electricity charges (about 20 paise/kWh) to the utility From the society's point of view, however, part of the capital costs of generation and transmission are to be attributed to the pumpset load. We have adopted the figure of 75 paise (Rs 0 75) per kilowatt hour, as the shadow price of electrical energy, from the report of the Swiss Development Corporation Agency in 1983 (Bhatia, 1984 and Swiss Development Agency, 1983) A shadow price of 'C I F price plus 25 per cent' has been taken for diesel oil and lubricant oil used in the diesel set Information regarding repair and maintenance obtained from field studies done by REC, is adopted

Table 5 shows the comparative position of a 5 hp electric versus a 7 hp diesel pumpset It can be seen that the considerable gap in costs between the electric and the diesel pumpset narrows significantly when evaluated at social costs

Table 5 Cost comparison—electric and diesel pumpsets

Item	Private Costs (Rs)		Social Costs (Rs)	
	Electric 5 hp	Diesel 7 hp	Electric 5 hp	Diesel 7 hp
I Capital Costs				
1 Cost of pumpset	4600[a]	7650[a]	4600[a]	7650[a]
2 Pumphouse	1000		800[b]	
3 Generation			20000[c]	
4 Transmission			10000[d]	
5 Connection costs			10500[e]	
6 Cost of infrastructure for diesel transport				500
	5600	7650	45900	8150
II Operating Costs				
1 Energy charges	750[f]	7626 5[g]	2812 5[h]	7756 7[g]
2 Repair and maintenance	400[i]	1600[i]	400	1600
	1150	9226 5	3212 5	9356 7
III Present value of operating costs assuming 10 years life 10% discount rate	7060	56641	19722	57440
Total (I + III)	12660	69291	65622	65590

Notes to Table 5

a Costs given by regional distributors of Kirloskar Oil Engines and Kirloskar Brothers Limited, New Delhi

b Taking shadow wage rate labour component (5 hp)

c For a 3 25 kW connected load, an approximate capacity addition of 2 kW is needed at the generating end Approximately, 1 2 kW is needed for the energy alone, in view of the marked seasonality involved, a higher figure of 2 kW appears justified Present cost of Rs 10000 per kW for steam generating capacity is taken

d Fifty per cent of the cost of generation is attributed to transmission and distribution according to prevailing norms

e This figure is based on a set of recent schemes sanctioned by the REC

f Based on 1000 hours of annual operation

g In the private cost calculations, price of diesel includes the taxes (Sales Tax, Octroi, Toll Tax) imposed by the government on diesel oil wheras the shadow price is equal to C I F price plus 25 per cent Obviously, the tax part is not included in the social cost calculations

h Shadow price of electrical energy taken as 75 paise/kWh which is different from the average cost as shown in Table 5 Average cost includes both the capital and operating costs But shadow price is only that of the energy charges Also 75 p/kWh is justifiable as many studies have indicated the shadow price to be even more than this A study by The World Bank for the state of Orissa has estimated the shadow price to be Rs 3 00/kWh

i Rural Electrification Corporation, field survey reports

As seen in Table 3, apart from four states, all others operate their pumps for less than 1000 h/year and this has implications for the comparative cost analysis If the above calculation of costs in Table 4 is performed for an operation of 700h/year, the comparative costs work out to be Rs 60,442 for electric and Rs 51,305 for diesel

It is, therefore, clear that the large effective subsidy given for the use of the electric pumpset has a major role to play in the choice of the source of energy

PUBLIC VERSUS PRIVATE TUBEWELLS

So far we have considered decentralized pumping options in contrast to private tubewells/pumpsets operated by electricity supplied from a central grid. One more possible waterlifting option using grid electricity is the system of public tubewells prevalent in some parts of North India These are owned and operated by 'public' bodies, such as the State Irrigation Departments, which levy water charges from the farmers on the basis of previously notified rates The number of public tubewells is about 51,000 in the country as against nearly 5 2 million private tubewells. Public tubewells generally have water lifting capacities of 150 or 300 m^3/h and are used to irrigate large areas of about 100 ha and above On the other hand, private tubewells of lesser capacity are generally used for farm sizes of 2-2 5 ha A comparison between these two options follows [13]

The efficient working of public tubewells calls for an independent transmission line that would connect a cluster of public tubewells to the 33 kV-substation In general, these "dedicated" feeders serve about 25 public tubewells and also require separate control facility at the substation.

Public tubewells offer considerable savings as compared to private tubewells, both in capital and operating costs, as shown below:

1 Most public tubewells are designed to irrigate 100 ha, with a delivery capacity of about 150m^3/h, and have an average connected load of 15 kVA Private tubewells irrigate about 2-2 5 ha, and have a motor capacity of about 2.2-3.7 kVA. In order to irrigate 100 ha, 40 to 50 private tubewells will be required As average cost of energizing a private tubewell is about Rs 10,500.[14] The connection cost for irrigating 100 ha through private tubewells, would, therefore, be in the range of Rs 420,000 to Rs 525 000 On the other hand, it is estimated that the connection cost for a public tubewell of 150 m^3/h capacity, is about Rs 70,000, including the cost of a 'dedicated' line and power system improvements For a 300 m^3/h capacity tubewell irrigating 200 hectares of land, the connection cost is Rs 78,000 The connection cost would therefore be Rs 700/ha and Rs 390/ha for a 150 m^3/h and a 300 m^3/h public tubewell For private tubewells, the cost is in the range of Rs 2,470 to Rs 3,088/ha, assuming that the two systems meet the same irrigation requirement

2 A group of about 25 public tubewells could be connected to a "dedicated" feeder This would require a connected load of 375 kVA and would serve 2,500 ha To irrigate the same area through private tubewells, the required connected load would be about 3,300 kVA The cost of generation, transmission and distribution upto the 11 kV point, is about Rs 3,500/kVA There is, thus, a saving of about Rs 10 2 million (in terms of capital cost alone), if we have to irrigate a 2,500 ha area using 25 public tubewells, in place of private ones

3. During the agricultural peak demand period, it is estimated that the current drawn by a public tubewell is equivalent to about one-ninth of the current drawn by a set of private tubewells for irrigating an area of about 100 ha [15]

4 In practice, efficiency (i e the amount of water lifted to the amount of current consumed) is in the range of 20-30 per cent for private tubewells, and about 50 to 60 per cent for public ones Though public tubewells are more cost-effective, farmers obviously find the private tubewells more convenient than to depend on an external source of supply involving some dependence on the public tubewell operator, who is generally a department official.

RELEVANCE OF THE RURAL ELECTRIFICATION PROGRAMME TO POWER SHORTAGES IN INDIA

In a shortage situation, it has been the stated policy of the State Electricity Boards to give preferential supply to agricultural consumers, and to inflict the severity of the shortages largely on industrial consumers of different categories The monthly reports of the Central Electricity Authority clearly show that the powercuts are largely imposed on industry, and agriculture is assured of a minimum supply ranging from 7 to 12 h a day.[16] Considering the average number of hours the pumps are required to run for irrigation purposes, it is undeniable that this is sufficient to meet their requirements.

POWER SHORTAGES

Power shortages have been endemic in India in recent years These are due to a combination of factors, including delayed implementation of power projects, with shortfalls in planned capacity additions ranging from 36 to 50 per cent during the period 1960-1980, and inadequate operating performance, especially of thermal power plants (Committee on Power, 1980).

Recent official reviews forecast peak deficits in all but the North-Eastern region, and small surpluses in all but the southern region of India However, it may be pointed out that the assumed performance norms underlying the above estimates, are extremely unrealistic In the case of thermal power plants, which form the minor component of generating capacity in the Indian system, the assumed plant load factors are 57 per cent for units below 200 MW and 61 per cent for units of 200-210 MW, whereas the actual plant load factors range from 44 to 48 per cent during the last 4 years If more realistic performance norms for thermal stations are used, the deficits are much higher [17]

FUTURE POLICY OPTIONS AND RECOMMENDATIONS

The analysis of the present and likely future power shortages show that the industrial sector is likely to face problems of power supply in the future as well, unless (i) the policy regarding preferential treatment to agricultural electricity consumption undergoes a change, and/or (ii) there is an increased power availability in the country as a whole Our assessment is that neither of the above conditions is likely to be fulfilled in practice In view of the importance of assured irrigation for agricultural production, and also in view of the political strength of the agricultural sector in this regard, a continuation of the present policy of an assured minimum supply of electricity for agriculture seems to be a near certainty in the future as well Power availability is also unlikely to improve in the near future and, on the contrary, is likely to deteriorate because of possible slippages in generating capacity additions

It, therefore, appears imperative to examine whether any of the requirements of electricity in the country can be met from sources of energy other than grid electricity It is in this context that the economics of alternative systems for pumpset irrigation become relevant.

The pumpset load appears to be ideally suited for decentralised systems of energy supply This is not the case for large and medium industries, which still consume a major amount of electricity [18] The scattered nature and the low level of utilisation of the pumpset loads are specially important in this regard We have already seen that, evaluated at social costs, the pumpset requirements can perhaps be economically met by alternative systems.

During the period 1980-85, about 350,000 electrical pumpsets per year are expected to be added to the system For the period 1985-1990, the targeted addition is 600,000 electrical pumpsets per year Even if we assume that the actual annual

addition during this period is only about 400,000, the addition to the connected load would be 1400 MW per year for this additional pumpset load alone [19] This would also imply that the additional energy requirement in 1989-90 would be 7000 GWh, for the country.[20] The energy shortages in the country as a whole are more than this estimate If this additional requirement is met from sources other than electricity, the shortage would obviously go down significantly and more power will be available to the industrial sector, apart from increasing the overall availability of power in the system The above analysis could be conducted in a more detailed fashion taking state-wise and region-wise figures of pumpsets, etc However, the objective of this paper is only to highlight the policy options open in the rural electrification programme and to bring out the conscious need to introduce alternative decentralized irrigation technologies

In conclusion, the policy recommendations in the rural electrification sector may be summarized as follows.

1 A conscious attempt should be made to encourage alternative irrigation technologies this would perhaps involve discouragement of additional electric pumpsets, and encouragement of diesel, diesel-cum-biogas pumpsets etc , in the first instance It would also involve selective expansion of public tubewells in place of private tubewells

2 The alternative may first be considered for the additions to the pumpset demand over the next few years

3 A detailed evaluation of the 'shortage costs' in the industrial sector needs to be made Estimates available from some of the recent studies appear to be only guesses based upon estimated relationships between energy consumption and output/value added (FICCI 1984) One possible method of doing this is by estimating the customer shortage costs for industries by using econometric methods Sample surveys regarding losses caused by powercuts, viz lost output, spoiled products, spoiled raw materials, etc , have to be conducted in different industries to arrive at an estimate of shortage costs (Sanghvi 1982) This is an area of further study [21]

4 An attempt should also be made to rationalize the electricity pricing for irrigation pumping to bring it more in line with social costs Raising electricity prices will also increase the financial returns to the power industry, thus making it more viable for consumers who would have a more rational energy choice based on the cost of service. Alternatively, similar subsidies will have to be given for the use of alternative pumping technologies

NOTES

1 It must be explained here that a village is considered to have been 'electrified' once the electricity distribution network is extended to the village and the first connection given, 'electrification' of a village, therefore, implies 'access to electricity', the further availing of the service is dependent on a variety of other, factors which we shall be discussing in this paper A 'village, is defined in the census as a locality with a population less than 10,000

2 This, of course, is subject to the availability of electricity The unreliable electric supply has resulted in the emergence of backup systems

3 However, it results in over-capitalisation and consequent under-utilisation of capital in this sector.

4 This was the situation in 1979-80 The situation has, in fact, become worse, as agricultural tariffs generally have not kept pace with rising costs in the last 4 years

5 This is based on information gathered by the authors from personal discussion with officials of the Rural Electrification Corporation and some major state utilities

6 The above are also countries which have a large pumpset programme The other Asian countries do not depend heavily on pumpset irrigation (i e based on groundwater) but on surface irrigation such as canals, etc

In Bangladesh, the rural electrification programme started out with a household emphasis, but has recently increased the number of pumpsets electrified However, the significant difference in emphasis between India and the other countries mentioned here, remains

7 The annual load factor of an electric pumpset is defined as the number of running hours of the pumpset divided by the total number of hours in the year.

8 Sengupta has shown the inefficiency of the distribution network in Karnataka, and how distribution losses can be minimised by appropriate modifications in the network

9 Monthly Bulletins, *Power Supply Position in the Country*, published by the Central Electricity Authority, New Delhi, clearly bring this out.

10 The definitions of 'advanced' and 'backward' areas depend on economic characteristics such as per capita income, level of industrialization, present electrification status, etc

11 There are some important differences in the items of cost included in the two papers, especially with regard to capital costs of generation and transmission

12 This is because the efficiency of a diesel engine

is less than that of an electric engine where efficiency is defined as the ratio of the brakehorse power to the indicated horse power.

13 This comparative analysis is partially based on information in the 1982 World Bank Report (unpublished) on the "Second Uttar Pradesh Public Tubewell Project" The authors also had useful discussions in this regard with Mr Byrappa, formerly Chief Engineer of the Rural Electrification Corporation, New Delhi, who clarified many technical points of comparison

14 This is the cost of 'connection'

15 These observations are qualified to some extent by the fact that, utilities often have different 'blocks' of six to eight hours' supply in different parts of the state system, thus evening out the peaks

16 This preferential policy has continued ever since power shortages appeared in the economy, governments of different political parties have been remarkably uniform in this matter

17 Detailed calculations are not presented here, they are available with the authors

18 Of course, cogeneration would improve the power supply situation to some extent, as far as industry is concerned A detailed discussion of the cogeneration potential in Indian industry, is outside our present purview However, available information indicates that cogeneration can possibly reduce only a small portion of the gap between supply and demand for power, and the observation made here remains valid

19 Taking an average connected load of 3 5 kW per pumpset

20 Assuming 1000 working hours in the year

21 It is understood that the National Council of Applied Economic Research, New Delhi, has initiated a study of power shortages and their costs to the industrial sector.

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ENVIRONMENTAL ISSUES 1 & 2

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1. Introduction

The impact of energy on the environment is only one of many interactions in a complex technical, economic, and social structure. The power sector, in many countries the largest single energy producer, is frequently in the public focus and is usually the first one called upon to abate any detrimental effect. Clearly, this may be different from country to country, but in the industrialized western countries electricity generation has been made responsible for severe environmental damages and, concequently, the regulatory bodies have introduced stringent emission standards. Regretably, I am not familiar with the situation in India and I will restrict myself to describe the issues central to the environmental concern in Germany, the development of standards, the implication of their enforcement, and how the utilities have coped with the problems. The situation is similar in other industrialized countries and the global nature of environmental concerns is likely to press the issues also in the developing world. Early awareness may help to treat the situation better than in older industrial areas.

2. Environmental Impact of Energy Use

Before focusing on the particular aspect of electricity or even energy, the term "environment" will be defined more exactly and the various natural and man-made effects described in a broader fashion to put the problem in its proper perspective. Environment is the physical and biological surrounding of the human species, and the interactions work both ways. Human history has been a constant struggle against adverse natural conditions and a fight to survive. Only in recent years has energy multiplied man's muscular strength and given him the power to shape the environment to his needs- and potentially destroy it.

All future projections, like for instance GLOBAL 2000, of the world's population, income, and resource utilization imply significant consequences for the quality of the environment. Virtually every aspect of the earth's ecosystem and resource base will be affected; be it agriculture and forestry, water supply and clean air, or even the global climate.

Energy's role in the system is twofold; on the one hand, energy availability could alleviate the pressure on firewood and improve agricultural yields, but on the other, energy consumption add to the pollution of the atmosphere, the soil, the rivers and oceans. In the following, we will describe shortly the areas of most frequent concern: waste heat and chemical pollution of trace substances.

The laws of thermodynamics allow only a fraction of any energy form to be converted into another, i.e. all energy conversion cause energy losses, which are dissipated in the environment as heat. The waste heat transmitted from the earth's surface to the atmosphere may have local or global effects on the climate. A change in the global climate has so far not been observed and is not expected for heat emissions less than 1% of the solar energy reaching the surface of the earth (ca. 1 kW/m^2). The world's energy consumption at the present amounts to roughly 10^{-4} of the solars input or a factor of 100 below the critical value. Although locally, in large cities or conurbations, the energy use may equal the insolation rate and give rise to changes in the micro-climate.

The combustion of fossil fuels results in the emission of various chemical pollutants. The most prominent are CO, NO_x, SO_2, C_nH_m, halogens, and heavy metals. The special role of carbon dioxide, CO_2, and its possible effects on the climate is discussed later, Nuclear power releases small amounts of radioactive materials in the air and with the coolant water.

To assess the effect of pollutants on the environment the complex process of transport and exposure has to be analysed; i.e. how emissions are transformed to immissions and how these effect huma beings, other living species, plants etc. There are today few conclusive chains of evidence linking the presence of a particula pollutant to a specific damage to the environment. The existence of acid rain, photogenic smog, soil acidity etc. is evident, but which concentration should be deemed permissable and hence which emission standards set, is debatable and attracts much controvers in industrialized countries and in the Third World.

Historically, the primary aim in environmental policy has been health effects and to secure the food supply.In the wake of industrialization many incidents are recorded where pollution has led to illnesses and premature decease. This was the case in Germany in the last century, and e.g. in London in the 1950s. Now attention is turning to more secondary effects, like the general qualitiy of air and water, and potential long term deterioration of farm land and forests. In Germany, severe damages have been observed in the various forest areas. More than 50% of all trees are effected in one way or another and many are dying. The phenomenon has already coined a new word "Waldsterben", which has won even some international validity.

3. Emission Standards

The growing awareness of environmental matters has led to new legislation controlling pollution and setting standards for emissions. In energy planning and environmental control the electricity sector takes a prominent place, as electricity is an energy form of general utility and pollution control measures can more easily be implemented in large central stations. Power plants burning coal, oil or gas emit considerable amounts of SO_2, NO_x, and other chemical pollutants as well as particulates in the case of coal.
In 1983 new standards for fossil fired boilers larger than 50 MW-th were introduced in Germany. They apply to all new units. Old ones were given time till mid-1988 for backfitting or will have to be shut down before 1993. The basic emission standards now in force are:

- Dust: 50mg/m^3 for coal fired boilers
- SO_2: removal of 85% from flue gas, maximum concentration 400mg/m^3, in some areas 200mg/m^3
- NO_x: 200mg/m^3 for coal, less for oil and gas

In comparison with other OECD countries, the standards are at present the most stringent ones. Numerous problems arise from different national environmental requirements, and efforts are undertaken to try to harmonize regulations in neighbouring countries.

4. Emission Abatement

The measures to reduce emissions from fossil boilers are many and have to be tailored to the fuel and the combustion process. A destinction is made between primary and secondary measures. In the first case, the pollutants are prevented from being produced at all or they are removed during the combustion itself. The fuels are cleaned, combustion parameters such as temperature, air surplus, mixing rates etc. are optimized or absorbents are added in the furnace. These measures are cheap but, in general, they can only with difficulties be applied to existing designs. In most cases, secondary measures will have to be taken to clean the flue gases. They are expensive and require additional and bulky equipment.

The modern stations built e.g. in Germany are equipped with dust cyclones and electrostatic filters with retention rates of more than 99.5%. Desulpherization equipment is an integral part of all new plants and is being back-fitted in older ones. In the majority of cases, wet flue gas scrubbers are used and the end product is gypsum. Some of it is sold to the building industry and some of it will be deposited as solid waste. Other techniques are under development but has not yet gained commercial acceptance.

Fluidized beds enable sulphur to be removed during the combustion process by adding limestone to the fuel. For smaller size boilers less than 200 MW-th say, the technology is now starting to be use commercially. Due to the low temperature in the bed, 800-900 C, the formation of nitrogenoxides is very low.

In other boilers, the concentration of nitrogenoxides will have t be reduced with additional primary and secondary measures. The very rapid introduction of NO_x emission standards in Germany left Selective Catalytic Reduction (SCR) the only viable technical and commercial option. The technology, originally developed in Japan had to be adapted to various types of coal and different operati characteristics in Germany. In the meantime, important progress has been made with optimized furnace geometries and new low-NO_x-burners. It may well be that future plants can meet emission standards with primary measures alone,- or with only minor flue gas cleaning equipment.

Airborn pollutants are being effectivly reduced, and sulphur and nitrogen emissions from the power sector will fall by a factor o 3 or 4 in the next few years. This in itself is a major success, but some problems are transferred to liquid and solid wastes. Policies and regulations should approach environmental matters i a holistic way in order not to create new problems in solving ol ones.

5. Cost of Environmental Reduction

The environmental impact of energy conversion is not restricted airborn pollutants. In the electric power sector measures have t be taken for cleaning waste waters, for disposing of ashes and filter residues, for sound deafening, and general site cultivation. For a new power station burning brown coal one thir of the plant costs of 1.6 10^9 DM 1984 (roughly $800 billion) for 600 MW-electric unit are attributed to various environmental control measures.

Sulphur dioxide removal with FGD equipment is a costly operation which varies with the type of fuel and size of the station. For typical 350 MW-el unit burning hard coal, the plant costs are increased by $125/kW. Retrofitting existing stations adds 10-30% to the figure. In some cases significantly more, as the experien with old brown coal plants have shown.

The primary measures to prevent NO_x formation may cost as little as $5-10/kW. Installing SCR equipment 'in the flue gas stream inc costs of typically $60/kW, out of which some $20/kW are for the initial catalyst. The catalyst has a limited lifetime of 3-5 ye and then needs replacement.

The cost penalty per generated kilowatthour runs to 12-15 mills for a large new coal fired station operated at 4000 full power hours per year. As the additional costs contain a large fraction of fixed costs, the capacity factor is an important parameter in determining the economic implications of environmental abatement measures. The total investments initiated by the new emission standards amount to roughly $14-14 billion for the power sector alone.

Clearly, the environmental problem[illegible]tify the initiatives taken, and the power industry has reacted [illegible] speedy and efficient construction programmes. This inevitably, has meant using existing or adapted technologies which under strong time pressure have proven to be expensive. During the programmes some development has been achieved and prices have come down, most notably for SCR catalysts. With increasing building and operating experience it seems possible to develop simpler and less costly technologies.

6. Nuclear Power

Nuclear power already from its inception was faced with very stringent health and environmental requirements. There is more knowledge of radioactive effects than of any other pollutant and the standards are more severe than for any other source of energy. Mankind has always lived in a natural radioactive environment and under normal operation a person living close to a nuclear reactor receives an additional dose of less than 1/1000 of the natural background (ca. 200 mrem/a in the F.R.G.). In the licensing process proof is required that during all normal conditions no person will be exposed to more than 30 mrem, which is eqivalent to the variations in the natural background in Germany. Past records show that the exposure has been much less, typically 0,1 mrem per year.

The major hazard of radioactive release from reactors stems from accidents. The Chernobyl accident in 1986 caused radioactive fall-out not only in Russia but over large areas in Europe. Even if the actual exposure in Germany was small (on average <50 mrem in the first year) and any health effects are likely to be negligeable, it strongly enhanced existing and latent anti-nuclear feelings. The political parties are divided on the matter, and a further expansion of the nuclear programme in Germany and other Western European countries encounter great problems. Energy planning in utilities is more and more becoming a political exercise.

Various studies, like the Rasmussen Report, have attempted to assess the risk of nuclear power on a probabilistic basis. Even with very pessimistic assumptions the risk is very low and less than for most other man-made and natural events. Recent results from refined analysis indicate a further reduction of the risk by orders of magnitude. Still, the probabilistic approach to nuclear

safety has difficulties in winning public confidence- and more so after the fatal Chernobyl accident. A deterministic approach showing that even in the worst of all cases, no harm will come to the public may have a better chance. This would involve reactor design with strong inherent safety features relying mainly on passive systems to prevent a core melt-down. Such systems are being studied,e.g. modular HTR or the PIUS type LWR. Efforts are under way to have first prototypes constructed and tested.

The nuclear reactor is only one part of the nuclear system, comprising uranium mining, enrichment, fuel fabrication, reprocessing, and final disposal of radioactive residues. In particular the reprocessing of irradiated fuel and the entombment of high level waste or whole fuel elements in underground stores pose new and challenging environmental questions.

7. The Global Dimension

A comparison between alternative energy chains, from the primary energy resource to the final energy utilization, enables a better insight into their relative merits. Such studies have been performed, for instance for the generation of electric energy, with the result that natural gas and nuclear energy are the technologies with the smallest health effects, measured in fatalities and injuries. Even solar thermal conversion ranks higher due to the large demand on materials and man-power in the construction phase.

Environmental questions can be addressed only on a global scale. Airborn chemical pollutants from fossil combustion travel far, from the US to Canada or from Continental Europe to the Scandinavian countries. Before introducing the stringent emission standards in Germany, one half of the SO_2 emitted was "exported" and at the same time a similar amount was "imported". Clearly, solutions to the problems of clean air and water can only be sought internationally, and national efforts must be coordinated.

A problem looming on the horizon is the potential hazard resulting from increasing concentrations of CO_2 in the atmosphere. Deforestation and combustion of fossil fuels have been major contributors of CO_2, the concentration of which has been rising steadily for the last 100 years, as observations at Mauna Loa, Hawaii show. By all probability, the trend will continue and scenarios calculate a possible doubling of the CO_2 content of the atmosphere within the next 100 years.

The absorption qualities of carbon dioxide molecules are such that shortwave solar radiation pass through the atmosphere to reach the earth's surface, whereas re-emitted longwave heat (infrared) is absorbed, resulting in the "green house" effect. The global heat balance can be maintained only by an increase in the temperature of the surface and the atmosphere. The climatic implications could

have serious consequences for rainfall and surface temperature of large areas of land and also for the sea levels. At present, there still remain uncertainties with respect to the CO_2 balance as well as the interaction with other trace substances. The possible effects on the climate are hotly debated among scientists, but the result could be potentially disastrous. Conclusive answers will be manifest only when climatic changes are irreversible. Many meteorologists maintain that the weather extremes observed during the last decade are the first signals of a climatic disturbance.

8. Future Development

The development takes place on various levels: the technical, ecological, and the political one. Present emission retainment technologies are being improved; flue gas desulpherization is achieving efficiencies of 95% and more, selective catalytic reduction of nitrogen oxide is better able to cope with varying operating parameters and progress with catalysts has led to lower costs. More important, the optimization target in combustor design has moved towards lower environmental impact. In practical terms, NO_x and SO_2 are controlled during fuel combustion in lean burners and fluidized beds.

New thermodynamic conversion processes like combined cycles are reaching higher efficiences due to improved gas turbine designs. Natural gas fired combined cycle plants approach a net efficiency of 50%, and, before long, this will be the standard for modern fossil electric plants. The utilization of coal in electricity generation is moving into new avenues like pressurized fluidized beds and gasification. Together with combined cycles, coal may in future be converted to electricity with a net efficiency of 45% or more. Improving conversion efficiency is a universal means of reducing the environmental effects of electricity generation. Waste heat dissipation is lower, less pollutants are emitted, and also the global concern over CO_2 may be allayed.

Environmental policies are starting to see the multidimensional picture of the problem and to work towards international and global solutions. On the national level, new approaches to achieve the goal of reductions in total emissions are being discussed. In Germany, standards have been set for each unit. In the USA, integral values have been proposed for larger areas, and in Denmark for the power industry as a whole. Within an emission framework the most economic solution may then be sought and the decision left to the operators of the plants.

As the environmental control technologies are being improved, the means for further reductions are at hand and the question is how to implement them in the most efficient way. The classic debate is between the carrot or the stick method. Both incentives and penalties have been used in policies around the world and the results have varied.

The global dimension of the environmental problem is just starting to be recognized. The actions to reduce the impact on nature will always have to be on the national level but they should be taken within the international frame. The experience gained should be shared and used to mutual advantage, and past errors not repeated over again.

IMPACTS OF POWER SUPPLY INADEQUACY IN DEVELOPING COUNTRIES

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IMPACTS OF POWER SUPPLY INADEQUACY IN DEVELOPING COUNTRIES

Arun P. Sanghvi[1,2]

1. INTRODUCTION

The essential role of an economic and reliable supply of electric power in economic and social development, and in industrialization is widely recognized. Whereas, much has been written about the precise nature of this relationship (i.e., the income and price elasticity effects), there is a clear consensus that a "strong" linkage exists between these variables.[3] Unfortunately, many developing country economies are seriously hampered by inadequate power supplies. The objective of this paper is to draw attention to the short and long-run economic impacts of power supply inadequacy in developing countries. Some policy implications related to this problem are discussed as well.

Adequacy refers to the power system's capability to meet the electricity demand and energy requirements of all its customers. Inadequacy can arise either due to insufficient capacity -- generation or network -- to serve load (kW) at any instant in time; or it can arise due to insufficient energy (kWh) to serve customer requirements over a period of time. In short, adequacy refers to the reliability, i.e., certainty of the availability of power.

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2 This research was funded in part by the Electric Power Research Institute (EPRI), and by the United States Agency for International Development (U.S.A.I D.). However, the opinions and analysis presented herein are solely attributable to the author.

3 The controversy surrounding this relationship has centered largely around demonstrating the extent to which in the long-run this linkage may not be rigid, i.e , not immutably fixed, and that furthermore it may have changed in the last fifteen years because of the effect of other key variables such as electricity prices, the price of energy substitutes, and the prices of complements (i.e., machinery, appliances) [19], [38].

In the United States (U.S.), power supply interruptions are infrequent. The overall system reliability index expressed as the percentage of energy demand met is of the order of 99.98 percent [48].[4,5] Service interruptions due to generation capacity deficiency are virtually unheard of. The overwhelming majority of outages (+98 percent) that U.S. consumers face are due to faults in the transmission and distribution network. Most of these outages are of short duration, typically lasting from a few minutes up to an hour or two.[6]

In contrast, the reliability picture in many developing countries is substantially different. Most developing economies are capital constrained and therefore many are unable to provide adequate generating capacity reserves. This situation is often further exacerbated by poor operating availability of the existing power plants. Whereas the specific factors vary by country, the most common reasons for poor plant availability include inadequate preventive maintenance, lack of spares, inferior quality fuel supply, labor problems etc. In developing countries, it is not uncommon to find plant availability factors of .35 to .55 [22]. In contrast, plant availability factors in the U.S. are of the order of .70 to .85.

In some developing countries, the generation deficiency is so acute that they are accompanied by severe energy deficiencies as well. In other words, even if peak period demand levels (kW) were trimmed so that operating reserves were adequate at such times, the energy capability of the system on a daily basis is insufficient to meet energy requirements.

Another reason for poor power supply reliability in many developing countries is the poor state of transmission, and especially the distribution network which is often

4 Numbers in square brackets relate to the numbered list of references at the end of this paper

Marginally lower indices have been reported historically for many European power systems.

Studies of several utilities in the U.S. indicate that most consumers face of the order of 2 to 5 such sustained interruptions annually. Customers in rural areas experience a somewhat higher frequency of outages. Not included in this frequency statistic are momentary interruptions, which are defined as outages under 1 minute in duration. These latter service interruptions generally result from transient faults on overhead lines which are automatically cleared within a matter of seconds. Distribution reliability planners in the U S typically use an explicit or implicit criterion of 45 to 90 customer minutes of expected total outage time per year, per customer.

overloaded and overextended and in an advanced stage of disrepair as well. Power supply authorities already strapped for capital are unable to undertake all the necessary network extension, rehabilitation, upgrading, and maintenance. Instead, scarce funds tend to be directed to prestige and visible projects like power stations, and dams.

A related problem to power supply inadequacy is that of poor supply quality.[7] Voltage surges and dips, frequency fluctuations, and other distortions of the waveform can cause extensive damage to electric motors and other sensitive equipment. This is also an endemic problem in many developing countries, one that imposes a high economic cost.

This paper is organized as follows. Section 2 begins with an overview of the methodology for assessing the economic costs of power shortages. Section 3 presents monetary estimates of some components of these costs for several developing countries. Finally, Section 4 touches on some policy implications for dealing with this problem.

2. MEASURING THE IMPACTS OF POWER SHORTAGES

Unreliable power supply results in both short- and long-term costs to an economy. Costs are measured in terms of the adjustments that the consumers (such as firms) facing unreliable power supplies make to mitigate their losses. The short-run is the period of time in which a customer can make changes in operating routines but is constrained to its use currently fixed capital equipment. The long run is the period in which the customer can also make adjustments to its fixed capital stock, given expectations of future power unreliability. These impacts and interactions can be illustrated in the context of a business or manufacturing firm.

When faced with a curtailment in electricity supply, a firm must adopt an alternative to the use of electricity. Typically, production must be deferred to a later time when the supply is resumed. If the plant is operating at capacity, then overtime production involving additional costs will be necessary. If the plant utilizes a continuous round-the-

[7] Whereas reliability refers to service continuity, quality refers to the provision of power within stated voltage and frequency ranges and with the right wave form characteristics.

clock process and is operating at capacity, then this avenue is not available and the shortage may result in a loss of sales. If the firm owns standby generation, then some of these adverse effects are mitigated, although the decision to acquire standby generation in a long-term adjustment. Further, the use of such equipment entails the additional expense of fuel for operation. In addition, this may entail foreign exchange cost.

Service interruptions may trigger costs related to product spoilage, and damage to machinery and equipment. Under conditions of uncontrolled load shedding and transmission and distribution outages, i.e., sudden interruptions in service without any advance notification, these costs can be very high. Under a situation of controlled load shedding, i.e., a service interruption with some advance notification, the firm can reduce such losses by re-scheduling activities and by implementing controlled and orderly procedures for shutting down and re-starting the production processes.

These activities also entail additional costs. For example, a 3-hour load curtailment may entail a 1-hour preparatory phase prior to the load shedding to shutdown the process, and a 1-hour startup phase following resumption of service, for a total downtime of 5 hours. In the case of an unplanned outage, a 2-hour outage may entail another 2 hours to clean up damage and spoilage and to restart production, for a total duration of 4 hours.

In summary, major components of the short-run direct costs of an electricity supply interruption are:

- opportunity cost of idle/underutilized productive resources (idle factor costs)
- shortage and damage costs
- shutdown and restart costs

These costs depend critically upon a host of factors such the severity of the outage as defined by its time and duration-of-occurrence, magnitude, and extent of advance notification. In addition, these costs depend upon other factors such as the ability of the firm to make up lost production, as well as prevailing market conditions as regards the demand for the firms output and the ability to make up lost sales.

The most effective means of measuring these costs is by implementing a properly structured survey of businesses which incorporates an "economic worksheet". Questions would be included in the survey to obtain information on potential equipment and material losses and damages under different interruption scenarios of interest.

For estimating idle factor costs, the survey would incorporate questions that help the respondents to characterize their particular situation and what the corresponding economic repercussions are. Specifically, respondents are led through a structured sequence of questions to provide an accounting of lost down-time, re-start time, wages paid, overtime costs, savings in intermediate inputs, output losses that are deferred, as well as any permanent losses in sales. Once these components are costed out, the net cost attributable to the interruption can be directly estimated. This measurement approach has been applied in several past and ongoing studies in the U.S., Canada, and in other countries [5], [31].

Indirect Short-Run Costs

In addition to the direct costs noted above, in the short-run there may be indirect costs to the economy because of the secondary and ripple effects that arise as a result of the interdependence between one firm's output and another firm's input. These indirect multiplier effects can be significant when shortages are chronic and the severity of the energy shortfall is significant. Input - Output analysis is sometimes used to analyze the indirect effects of such electricity energy shortfalls [7], [21], [1], [3].

Long-Run Costs

Chronic electricity shortages and poor reliability of supply can trigger long-run [illegible] firms' expectations are that shortages and unreliable service will persist, then they will respond in one or more ways [24], [35], [8]. Examples of customer mitigation responses to poor reliability abound in developing countries. The extent of such adaptation, and the associated economic cost is nothing short of staggering in many instances. Some quantitative evidence of this impact is provided in the next section. However, much of the evidence is anecdotal [17].

For example, a significant fraction of households in some developing countries have installed one or more voltage regulators to protect appliances such as refrigerators, air conditioners, and television sets against potential damage from voltage fluctuations in grid supplied electricity. It has been reported that in some instances industrial electric motor windings have to be replaced on average once every year or two, because of poor power quality.

In a large number of apartment and office buildings in the city of Calcutta, it is reported that emergency backup generators have been installed to run essential equipment such as elevators. In the Punjab region of India, where grid fed electric pumpsets have played a significant role in the "green revolution", a large number of farmers maintain backup capability in one or more diesel pumpsets, to ensure against frequent interruptions in grid supply. A substantial amount of the total installed generation capacity in many developing countries (of the order of 20+ percent) is in the form of standby generation and self generation on the customer premises.

For a detailed discussion of the theoretical methods for measuring the short-run and long run costs of power outages and shortages, the reader is referred to references [24], [31], [35], [36], and references [9] thru [13].

3. ECONOMIC IMPACTS: COUNTRY SPECIFIC EXAMPLES

There is a paucity of reliable quantitative information on the economic impacts of electricity shortfalls in developing countries. Two recently completed studies nevertheless, underscore the point that the short- and long-run economic costs of power shortages can be high. These results are summarized in this section.

3.1 INDIA

Power shortages and unreliability were mostly sporadic in India in the 1950's and early 1960's. During this period the deficit situation was gradually deteriorating largely because generation capacity targets for the power sector in the five year plans were consistently not achieved for a variety of reasons (Exhibit 3-1). As a consequence, the

Exhibit 3-1

Power Sector Investments and Targets in India's Five-Year Plans

Plan (Years)	Capital Outlays Rs. (Crores)[1]	% of Total Plan Outlay	MW Target	%Shortfall From Target
I (1951-56)	260	13.3%	1,300	15.4%
II (56-61)	460	9.8%	3,500	35.7%
III (61-66)	1,252	14.6%	7,040	35.8%
Three Annual (66-69)	1,223	18.1%	5,430	24.1%
IV (69-74)	2,932	18.6%	9,260	50.5%
V (74-78)	5,244	17.8%	12,500	18.4%
VI (80-85)	19,265	22.9%	19,670	N/A
VII (85-90)	67,000	--	--	--
(85-86)	--	--	3,397	22.8%
(86-87)	--	--	4,460	5.3%

Source: [25], [4], [30].

1 1 crore = 1×10^7 Rupees.
At prevailing exchange rates Rs.1 is approximately 7 6 cents.

investment program has been "playing catch up" with demand, with the deficit situation getting progressively worse. By the 1970's power shortages became a chronic national problem that now afflicts most of the major states to varying degrees. Exhibit 3-2 provides a snapshot of the reliability picture during March 1986. On an energy deficiency basis, the total shortage nationwide is estimated to be of the order of 9 to 10 percent during 1986, and 1987 [44].

Estimating the cost of power supply inadequacy in a country like India is a difficult and complex undertaking. The vastness of the country and regional diversity in customer mix, industry structure, power supply situation, tariff policy, all call for a detailed disaggregated analysis at the State level. A recent study by the National Council of Applied Economic Research (NCAER) in India represents an attempt in this direction [26]. The NCAER study focused on the impact of power shortages in the industrial and agricultural sectors over the period 1982-1984[8]. Major relevant results of this study are highlighted in the following.

Industry

Questionnaires were mailed to a stratified random sample of 15,000 industrial units.[9] These units were chosen to ensure coverage of different industry types, which individually use more than 25 X 10^6 kWh annually, or more than 1 X 10^6 kWh at a given plant/factory site. The results reported in the study represent the 1,028 usable responses received.

Exhibit 3-3 summarizes the survey results on percent capacity utilization by industry type and geographical region, as well as the percentage of respondents who reported that power shortages were the primary reason for under-utilization of capacity. The results represent industry level average data and are based upon aggregating sample data using the appropriate sample weights.

8 In 1986, industrial sector electricity sales represented 40 percent of national consumption with the agriculture sector consuming 15 percent.

9 A corporation or "industrial house" that owns and operates several different plants.

Exhibit 3-3

Capacity Utilization And Reason For Below Capacity Production In The Reporting Units (1983-84)

Industry Type	Percentage Capacity Utilization				Percentage of Units Reporting Power Shortage as the Primary Reason for Below Capacity			
	Northern Region	Southern Region	Eastern Region	Western Region	Northern Region	Southern Region	Eastern Region	Western Region
1. Textiles	71 1	81.9	73 8	67 3	16.7	69.2	Nil	30.4
2. Cement Cement Products	NA	89.8	NA	70 0	NA	25.0	NA	Nil
3. Paper	50.5	63.7	85.4	50 3	100 0	50 0	33 3	20 0
4. Chemicals & Fertilizers	66 0	68.0	49.0	82.4	42.9	26.5	12.5	13.0
5. Electrical Industry	67.9	71.5	31.8	63.8	40.0	26.1	38.5	8.3
6. Iron & Steel	28 5	58.2	64.0	79 5	85.7	46.7	14.3	13.3
7 Non-Ferrous Metal	76 7	35.4	74.3	52 2	66.7	10 0	Nil	Nil
8 Engineering	93 0	69 2	40.0	51 9	33 3	28.6	68.0	Nil
9 Transport Equipment	43 8	90.1	72.5	97.3	33 3	16.7	50 0	Nil
10 Rubber	60 0	79.4	75 8	100 0	66 7	25 0	Nil	Nil
11 Coal Mining	NA	NA	92 0	92 2	NA	NA	100 0	Nil
12 Food Products	66.5	87.2	49 7	53 3	25 0	50 0	50 0	50 0

Exhibit 3-2

Power Cuts/Restrictions in Force [1] in India During March 1986

	Cuts	
	Demand	Energy
Delhi	Peak period restriction on industries	10%
Haryana	2 off days/week up to 3 3 86 on industries with 8 hrs/day supply and no cut thereafter with 100% demand cut for continuous process industries between 1800-2100 hrs.	50%
	Agricultural consumers were supplied power for 6-21 hrs./day.	
Mimachal Pradesh	Peak period restrictions on industries	.
Jammu & Kashmir	15 hrs /day suupply in Jammu and Srinagar for general industrial commercial, domestic and agricultural consumers	.
Punjab	30% demand cut between 1800 hrs-2200 hrs. with peak hour restrictions for industries getting supply from independent feeders including continuous process industries.	.
	Agricultural consumers were supplied power for 8 3/4 hrs -24 hrs./day depending upon day-to-day availability.	
Rajasthan	Peak period restrictions on industries	0-30%
	Agricultural consumers were supplied power for 8-10 hrs./day.	
Uttar Pradesh	Restricted supply for certain categories of industries. 1 day/week closure for general industrial consumers with peak period restrictions.	.
	Agricultural consumers were supplied power for 10 hrs./day.	
Gujarat	25-35% demand cut on general industries	.
	Agricultural consumers were supplied power for 10-24 hrs./day.	
Madhya Pradesh	10% demand cut to H T. consumers having contract demand more than 1000 KVA.	.
	Rural areas consumers were supplied power for 17 hrs./day 3 phase and 7 hrs /day single phase.	
	0% - 13%	
Maharashtra	24 hrs. power suupply rural areas	.
	0% - 20%	
Karnataka	Peak period restrictions on industries	0-70%
	15% - 40%	
Tamil Nadu	All A T [illegible], commercial, agricultural & industries with demand of 130 KVA and less were exempted.	15-40%
	Agricultural consumers were supplied power as per the grouping of rural feeders	
	15% - 40%	
Pondicherry	All H T essential commercial, agricultural and industries with demand of 130 KVA and less were exempted.	15-40%
	Agricultural consumers were supplied power as per the grouping of rural feeders.	
West Bengal	15% cut on H.T. industries and also peak period restrictions on industries	5-30%
Orissa	75% power cut on heavy and power intensive industries. However, these were permitted to draw power purchased from outside sources by OSEB (being available at present) to meet their requirement.	.

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1 Source Central Electricity Authority (CEA), New Delhi.

The data in Exhibit 3-3 indicate substantial variation in the extent of capacity utilization and its cause. In the northern, southern, and eastern regions, a substantial number of industrial units are constrained by power shortfalls. In comparison, the western region was least constrained in 1983-1984 by electricity shortages.

Total production losses in 1983-84 are estimated in the study to be Rs. 2,879 crores, which is approximately equivalent to $2.7 billion in mid-87 dollars.[10] Comparable estimates for the period 1982-83 based on the NCAER study are Rs. 2,199 crores, or approximately 2.1 billion in mid-87 US$. Production losses vary considerably by industry and region (Exhibit 3-4). For example, the loss in the iron and steel industry in 1983-84 attributable to power shortages was about 43 percent in the southern region, but only 3.5 percent in the western region. Averaged across all large industries in a region, production losses range between 1.46 percent in the western region to 13.16 percent in the eastern region.

The following potential sources of bias should be borne in mind in interpreting the estimates above. These estimates are subject to sampling error. In particular, the sampling frame for the survey consists of the large industries that tend to be more electricity intensive. Together, these industries account for about 80 percent of all industrial power consumption in India. In this sense the economic impact estimates understate the total costs of the shortfall.

The study estimates also understate actual economic costs because they do not include the costs of product spoilage, equipment damage, and process shut-down and re-start

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10 Based upon escalating 1983-84 Rs. to year-end 1986 Rs., converting the result to 1986 US$, and finally escalating year-end 1986 $ to mid-year 1987 $. Escalation rates and exchange rates obtained from:

(1) "International Financial Statistics Vol. XL, No. 6, June 1987, International Monetary Fund, Washington, D.C.

(2) "Economic Indicators July 1987," prepared for the Joint Economic Committee by the Council of Economic Advisors, 100th Congress, 1st Session, U.S. Government Printing Office, Washington, D.C.

Exhibit 3-4

Production Losses Due to Power Shortages in India
(1983-84)

Industrial Type	Average Loss as a Percentage Value of Production			
	Northern Region	Southern Region	Eastern Region	Western Region
Textiles	12.35	7.76	NA	2.31
Cement & Cement Products	N9	2.43	NA	NA
Paper	37.08	9.32	9.25	9.24
Chemicals & Fertilizers	1.30	15.71	30.90	0.72
Electrical Industry	6.30	5.81	6.48	0.52
Iron & Steel	37.07	43.41	12.57	3.45
Non-Ferrous Metal	15.17	10.40	20.00	Nil
Engineering	23.52	2.33	21.36	2.98
Transport Equipment	10.11	0.83	5.00	3.46
Rubber	50.25	14.33	NA	Nil
Coal Mining	NA	NA	8.00	Nil
Food Products	NA	NA	15.00	12.36
All Industries				
1. % of Loss	[illegible]	8.94%	13.16%	1.46%
2. Total Value of Production Loss (10^7 Rupees)[1]	407	620	729	229

[1] At 1979-80 prices.

costs.[11] Data from Pakistan discussed subsequently in this paper indicates that these costs can represent nearly 50 percent of the total costs of this shortfall.

Yet another potential source of bias may arise due to the manner in which the "production loss" figure is estimated. We interpret this to be mean loss in valued added. However, if this figure is simply estimated as the product of number of units of production lost and unit price, then the study estimates would be overestimating the true economic cost.

Finally, the primary thrust of the survey instrument was to obtain information about the amount of production (output) loss that is attributable to the power shortfall. The study attempts to get at this by asking respondents to focus on the level of plant capacity under-utilization that is solely attributable to the power shortage. This is sometimes difficult since under-utilization of capacity may be the result of other factors besides power outages, such a shortage of raw materials, labor strikes, and slack markets for the plant's output. The study attempts to correct for situations where respondents may have incorrectly overstated the case by attributing capacity under-utilization to the power shortfall problem when some of it is due to these other factors. Determination of whether such a situation indeed characterizes a given response and correcting for this bias has been accomplished in the study by examining ancillary data and applying the team's judgment. This process inevitably introduces some error as well.

The collective magnitude effect of these potential biases is not possible to estimate. However, it is somewhat comforting to note that order of magnitude estimates of the economic impacts of power shortages on Indian industry obtained in an earlier World Bank study, are comparable. Exhibit 3-5 superimposes the results of that World Bank study, which focused on the years 1974-1980, and the NCAER study, which dealt with

11 The NCAER study does report that a large fraction of the respondents -- typically 35 to 70 percent -- reported experiencing significant voltage fluctuations. However, estimates of damage to machinery as a consequence of this power quality problem varied substantially. Many industry groups perceived these costs to be very low, i.e., under 1 percent of the total invested capital plant. The highest costs were reported in the Northern Region by chemicals and fertilizers industry (14 percent), engineering industry (20 percent), rubber industry (8 percent), in the Southern Region by the textile industry (4.3 percent),and in the Eastern Region by the chemicals and fertilizer industry (5 percent), and by the engineering industry (5 percent).

Exhibit 3-5

Order-of-Magnitude Estimates of Power Shortages on Indian Industry[1]

Year	Estimated Shortfall GWh	Estimated Shortfall %	Loss of Value Added 107 Rupees	Loss As A % of GDP
74-75	10,953	14.1	1,630	2.6
75-76	8,599	10.3	1,300	2.0
76-77	5,124	5.8	810	1.1
77-78	15,837	15.5	2,500	3.0
78-79	11,186	10.3	1,750	2.3
79-80	19,068	16.1	2,980	3.6
82-83	N/A	-	2,199	1.3
83-84	N/A	-	2,879	1.5
84-85	N/A	-	3,500	-
85-86	N/A	-	3,739	-
86-87	N/A	-	3,993	-

1
a Years 7[illegible] upon [51] Years 82-84 based upon [26] Years 84-87 based on [15]

b. Cost estimates [illegible] all years do not include damage, spoilage, and process restart costs Any additional costs of operating more expensive captive/standby generation are also not included.

c Years 74-80 based upon the following simplifying assumption.

- All cuts are allocated to industry
- All power shortages are energy shortfalls
- A 2% impact on GDP is approximately equal to 1,500 core rupees per year

d Based upon exchange rate of Rs.13 12 to a dollar

the period 1982-1984. The World Bank study estimates are not based upon a survey, but represent "back-of-the envelope" calculations that employ the simplifying assumptions noted in the exhibit.

Agriculture

The agricultural survey comprised of a sample of 2,000 electric pumpset owning farmers distributed throughout India. Sample villages were selected on a stratified random basis in order to ensure that the sample was representative as regards topography, rainfall patterns and aquifer conditions, among other key variables. Up to nine farm households were interviewed in each selected village

Exhibit 3-6 shows estimates of ownership of electric pumpsets by state and the corresponding electricity consumption during 1983-84, based upon sample estimates that are appropriately weighted. The data shows that in some states there is substantial standby pumping capacity in the form of diesel pumpsets. The presence of this capacity is a direct manifestation of the problem of unreliable supply of grid power.

Estimates of production loss in agriculture attributable to power shortfall are also indicated in Exhibit 3-6. These estimates are not based upon a crop-response functions which relate crop yields to key inputs, including water usage. The use of such an approach is a very complex undertaking. Rather, the loss estimates in Exhibit 3-6 are based largely upon the perceptions of farmers in the sample.

It must be noted that crop losses will depend upon how good a rainy season was experienced. The 1983-84 season was considered to be "good" year for rain. Perhaps this is one reason why the costs are not as high as one might expect.[12] Another reason may be embedded in the evidence that there has been excess use of water by farmers. This practice of over watering has been stimulated in part by the low electricity tariffs charged to most farmers, by the fact that such supply is often uncontrolled-metered, and due to lack of knowledge about optimum water management strategies.

[12] Even if 1983-84 had been a bad rainfall year it is not apparent that the costs would be higher. This is because of the presence of standby diesel pumping capacity.

Exhibit 3-6

Ownership Of Irrigation Pumpsets, Electricity Consumption, And Production Loss Due To Power Shortage (1983-84)

States	Estimated Number of Electric Pumpset (000)	Estimated Electricity Consumption (GWH)	Percentage of Electric Pumpset Owing Households Who Own at Least One Diesel Pumpset (%)	Production Loss as Percentage of Total Production (%)
Punjab	410	1,885	91.60	1.89
Haryana	281	1,036	28.81	1.99
Uttar Pradesh	461	2,505	8.71	2.25
Rajasthan	252	800	4.57	5.11
Delhi	-	-	1.96	1.84
Northern Region Subtotal	1,404	6,226	23.40	2.38
Andhra Pradesh	491	1,250	0.77	2.47
Karnataka	305	451	1.96	3.06
Kerala	122	105	3.36	1.68
Tamil Nadu	964	2,217	0.00	1.51
Southern Region Subtotal	1,882	4,023	1.48	1.97
Bihar	181	514	52.69	5.30
Orissa	23	62	0.00	3.27
West Bengal	27	46	18.49	1.33
Eastern Region Subtotal	231	622	29.41	4.88
Gujarat	295	966	5.80	3.36
Maharashtra	821	1,936	2.44	1.63
Madhya Pradesh	419	400	0.00	2.01
Western Region Subtotal	1,535	3,302	2.41	2.19
All India	5,052	14,173	-	2.33

Long-Run Costs to the Economy

The economic loss estimates of power shortages to Indian industry and agriculture as reported in the preceding do not reflect the long-run costs to the economy of further inefficiencies due to the misallocation of capital in power generation and power conditioning equipment. Neither do they reflect the additional resource cost to the economy because of inefficient fuel use that is triggered by the inability of the power sector to provide adequate supplies of electricity.

Specifically, the most commonly reported mechanisms by industry for coping with power shortages are use of standby power generation, self generation, and production rescheduling. Though less common, a substantial number of industrial units make up lost production either by combining overtime or operating an additional shift. Exhibit 3-7 shows that the percentage of industrial units reporting some self generation is very high. Exhibit 3-8 further indicates that a substantial percentage of demand (kW) and energy (kWh) of several industries is met by self generation.

The data in Exhibit 3-8 also indicates that about 3,500 MW of self-generation capacity was installed in the industry sector, split largely between steam units and diesel units.[13] Additionally, the figures in Exhibit 3-8 do not reflect the large numbers of small units (less than 50 kW) installed by the commercial customer segment. Such small units do not have to be registered officially. Therefore it is difficult to establish quantitative estimates of how much capacity of this type is in customer hands. Nevertheless, there is evidence that this capacity is not insignificant.[14]

Thus, losses in productive efficiency arise by virtue of the fact that industry and many businesses must resort to the use of standby generation or self generation in order to meet their electricity needs. Diesel sets and small steam turbine installations do not achieve the operating economies that are realizable by large coal fired stations which

[14] In an eight month period in 1978, the State Electricity Board in Andhra Pradesh recorded that approximately 15.5 MW of small standby diesel sets had been purchased [51]. This represents an annualized rate of about 23 MW. The authorities are quoted as of the opinion that this annual rate was representative of the preceding 5 year period, and this in a state that is considered to have better than average reliability.

Exhibit 3-7

Use Of Captive Power Sets In The Reporting Units (1983-84)

Industry Type	Percentage of Units Reporting At Least One Captive Set				Average Capital Cost of Captive Plants in the Reporting Units (10^4 Rupees)			
	Northern Region	Southern Region	Eastern Region	Western Region	Northern Region	Southern Region	Eastern Region	Western Region
1. Textiles	100.0	76.9	100.0	77.4	9 31	7 37	10 94	13 58
2. Cement & Cement Products	NA	66.7	NA	NA	NA	50 96	NA	NA
3 Paper	Nil	50.0	83 3	22 2	Nil	466 13	14 25	35 83
4. Chemicals	16 7	53.7	69.2	29 5	380 00	25.65	9.55	17 23
5. Electrical Industry	28.6	67.9	76.9	15.0	19.17	5.25	9.14	3 86
6. Iron & Steel	14.3	50.0	69.2	26.7	24.35	19.37	641.04	878 60
7. Non-Ferrous Metal	100.0	60.0	100.0	50 0	2,077.66	3.23	7.78	NA
8. Engineering	33.3	63.6	64.7	30 0	0.25	2.45	10.25	8.91
9. Transport Equipment	50.0	64.3	100.0	12.5	66.25	11.92	19.15	10 00
10. Rubber	50 0	50.0	Nil	Nil	2 50	NA	Nil	Nil
11. Coal Mining	NA	NA	Nil	25 0	NA	NA	Nil	5 87
12 Food Products	25 0	66 7	100 0	Nil	NA	9.85	4 46	Nil

Exhibit 3-8

Percentage Of Demand (KW) And Energy (kWh) Met By Self Generation

Industry Type	Northern: Captive Power Capacity (kW) as a Percentage of Total Need	Northern: Self Generation as a Percentage of Total kWh Consumption	Southern: Captive Power Capacity (kW) as a Percentage of Total Needs	Southern: Self Generation as a Percentage of Total kWh Consumption	Eastern: Captive Power Capacity (kW) as a Percentage of Total Needs	Eastern: Self Generation as a Percentage of Total kWh Consumption	Western: Captive Power Capacit (kW) as a Percentage of Total Needs	Western: Self Generation as a Percentage of Total kWh Consumption
1 Textiles	35.8	13.4	33.3	20.5	-	-	31.8	2.7
2. Paper		-	39.3	32.3	30.8	21.2	41.3	30.9
3 Chemicals & Fertilizers	15.5	18.5	16.8	10.5	84.5	82.2	22.3	6.8
4 Electrical	54.3	45.2	37.9	25.9	49.4	17.2	20.7	0.3
5 Iron & Steel	19.6	9.3	5.6	6.6	32.8	36.3	28.8	30.2
6 Non-Ferrous Metal	87.5	88.2	35.9	23.5	36.5	12.0	-	-
7. Engineering	17.5	21.6	41.7	18.2	24.7	15.2	8.7	2.2
8. Transport Equipment	34.9	36.0	29.9	14.3	10.9	0.7	4.9	0.2
9 Rubber	82.8	89.3	43.3	10.1	-	-	-	-
10. Cement & Cement Product	-	-	17.0	7.0	-	-	-	-
11. Vanaspati	-	-	-	-	31.5	38.4	-	-
12. Coal	-	-	-	-	-	-	2.1	NA
Cost of Captive Generation (Rs./kWh) 1 Range	0.60	-- 1.28	0.70	-- 2.49	0.56	-- 4.18	0.54	-- 2.32
2 Central Tendency	0.90		1.50		1.75		1.75	
# Units 1/	420		583		685		806	
Installed 1/ Capacity (MW)	860		613		1,074		836	
% Steam 1/	74%		62%		75%		59%	
% Diesel 1/	26%		38%		25%		39%	

1/ Provisional estimates for 1982-83 provided by CEA

Exhibit 3-8 supply power to the grid. In addition, from a national perspective oil based fuels have a high resource cost to the Indian economy because valuable foreign exchange must be expended to import oil.[15]

These data suggest that long run productive efficiency may be severely compromised because of over capitalization of power generation and power conditioning equipment by electricity consumers. A fundamental policy issue that must be addressed in this context is what is the optimal allocation of capital investment in generation between the power authority/utility and its customers? Stated very simply, would the nation be better off if some or all of present capital invested by industry, business, farmers, and households in power generation and power conditioning equipment were to be invested instead by the power authority? We believe that from a national perspective, at present there is a substantial amount of misallocated capital investment.

In closing, the data and evidence at hand, whereas imprecise and incomplete, strongly suggest that if appropriate measures are not taken to rectify the shortfall situation in the power sector then in the long run the magnitude of economic losses and wasted opportunities in the Indian economy will be nothing short of crushing.

Exhibit 3-5 serves to dramatize the substantial cost of power shortages in India. Even if one assumes very conservatively that only 1.0 percent of GDP is lost each year, then the annual loss based upon 1986-87 GDP is about $1.5 billion. The present value of these losses if significantly unchecked over the next 30 years is approximately $14 billion in today's dollars, utilizing a discount rate of 10 percent. More realistically this cost is likely to be substantially higher because of the extremely conservative assumptions made in the preceding calculations.[16]

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15 An important and related [illegible] n the context of the agricultural sector in India is the question whether deployment of el[illegible] pumpsets makes any economic sense. A recent study has shown that electric pumpsets are econom[illegible] from a private perspective, largely because of the highly subsidized tariffs to this customer segment However, from a social cost-benefit analysis viewpoint, this option does not compare very favorably with alternatives such as diesel pumpsets or dual fuel (diesel-biogas)-fired pumpsets [4].

16 These estimates do not include spoilage, damage, and the costs of owning and operating captive power plants, and power conditioning equipment. Spoilage and damage costs can add up to 50% of the costs Furthermore, the present value calculation does not assume any increase in load and GDP.

3.2 PAKISTAN

Increases in residential demand, together with high pumping loads and the rural electrification program have contributed in large measure to the deterioration of WAPDA's[17] system load factor[18] from approximately 66 percent in 1975-76, to 56.5 percent in 1985-86.[19] However, WAPDA's generation capacity additions have not kept pace with demand, which, since the 1980s, has risen at an average annual rate of over 11.2 percent. Consequently, since 1982 the country has had power shortages. These shortfalls are expected to continue at the very least for the duration of this decade.[20]

Exhibit 3-9 presents estimates of load shedding for the period 1979-80 through 1984-85 The data show that the amount of load shedding has increased substantially in recent years.

17 Water and Power Development Authority of Pakistan. WAPDA's service territory includes all of Pakistan except for the major port city of Karachi and its environs that are served by the Karachi Electric Supply Corporation (KESC).

18 System load factor is defined by the ratio of actual utilization of all generating plant (hours/year) to the maximum possible utilization level of 8760 hours/year. Higher load factors imply more efficient utilization of generating plant.

19 Recent shifts in electricity consumption shares are as follows:

Consumer Segment	Percentage Share of Total WAPDA Sales 1970-71	1980-81	1985-86
Residential	9.78	20.49	29.11
Commercial	3.68	4.91	5.65
Industrial	44.28	38.40	38.02
Agricultural	27.03	23.44	18.58
Public Lighting	0.56	0.63	0.58
Bulk Supply	14.67	11.04	7.83
Traction	---	0.48	0.23
TOTAL	100.00	100.00	100.00
Total Consumption (GWH)			

20 Financial constraints are considered to be the most important barrier to a more rapid expansion of generating capacity. The power sector in Pakistan absorbs over 70 percent of the Government's energy budget, and roughly 30 percent of the country's total development budget. During the sixth Five-Year Plan, 1983-1988, the government allocated Rs. 87.4 billion, or 28.7 percent of total public sector outlay, for investments in the power sector. This amount is approximately equivalent to US$5 billion at recently prevailing exchange rates (Rs. 17.56 to a dollar).

Exhibit 3-9

Magnitude of Load Shedding in Pakistan (MW)

	1979-80	1980-81	1981-82	1982-83	1983-84	1984-85
July	-	-	-	769	-	-
Aug	-	-	228	-	-	878*
Sept	-	-	-	221	-	556*
Oct	-	-	-	-	-	600*
Nov	-	-	-	-	-	-
Dec	469	-	594	366	-	968
Jan	451	369	635	1,000	600	1,623
Feb	429	278	766	434	400	700
Mar	200	190	496	527	850	1,800
Apr	305	100	480	193	850	1,400
May	220	100	344	-	268	1,300
Jun	134	186	329	-	475	1,500

* Limited to system peaks from 17.45-19.45 hours.

Whereas load shedding previously was generally restricted to the period December through June, in recent years it is increasingly becoming a year-round phenomenon. Exhibit 3-10 provides further details about the frequency and duration of outages due to (controlled) load shedding and due to unplanned outages.

Estimates of the economic costs of load shedding in WAPDA's service territory presented in the following pages are quoted from a recently completed study that was funded by USAID and hereafter referred to as the USAID study [43].

Exhibit 3-11 presents estimates of the macroeconomic impacts of power shortfalls to industry. The 8.2 percent reduction in value added is equivalent to a decline in value added of Rs. 6.2 billion in 1984-85 (approximately $350 million in todays dollars). This is based upon the 1984-85 National Income Accounts which indicate a total sector value added of Rs. 75 billion.

Direct plus indirect -- cost of the shortfall of Rs. 9.3 billion represents a 1.8 percent reduction of GDP. Additionally, the study estimates that the adverse impact on

Exhibit 3-10

Extent of Variation in the Frequency, Duration and Total Incidence of Outages By Type of Industry, Process and Region (Annual Average Per Unit in 1984-85)

	Sample Size (No)	LOADSHEDDING Frequency (No)	LOADSHEDDING Duration (Hrs)	LOADSHEDDING Total Hours	UNPLANNED OUTAGES Frequency (No)	UNPLANNED OUTAGES Duration[a] (Hrs)	UNPLANNED OUTAGES Total Hours
A. BY INDUSTRY GROUP							
Food, Beverages & Tobacco	138	137	1.51	207	39	0.93	36
Textiles	208	100	1.61	161	39	0.95	37
Wearing Apparel & Footwear	27	58	1.33	77	29	0.72	21
Wood & Paper	63	121	1.36	164	39	0.5	19
Chemicals & Petro-Chemicals	90	62	1.60	99	34	0.88	30
Non-Metallic Mineral Products	46	80	1.43	114	33	0.88	29
Metal & Metal Products	117	110	2.17	239	31	0.84	26
Machinery & Equipment	136	110	1.87	206	27	0.63	17
Other Industries	18	149	1.20	179	19	1.26	24
B. BY PROCESS							
Batch-Making	544	114	1.75	200	34	0.79	27
Continuous	299	88	1.48	130	34	0.94	32
C. BY PROVINCE							
Punjab	440	158	1.80	284	41	0.56	23
Sind	335	34	0.88	30	26	1.42	37
NWFP	45	171	1.62	277	32	0.65	21
Baluchistan	23	0	0.00	0	15	1.93	29
D. TOTAL SAMPLE	843	105	1.67	175	34	0.85	29

a. The figures in decimals are proportion of an hour

b No loadshedding because of self-generation of power by all the sample units in the province.

Exhibit 3-11

Impact of Outages on Key National Economic Parameters By Type of Industry (a) (Pakistan, 1983-84)

	Reduction in Value Added (b) (%)	Reduction in Value of Production (%)	Reduction in Exports (%)
A. BY INDUSTRY GROUP			
Food, Beverages & Tobacco	21.2	2.7	11.2
Textiles	9.4	4.8	4.2
Wearing Apparel & Footwear	4.4	0.6	0.9
Wood & Paper	6	6.3	1.4
Chemicals & Petro-Chemicals	5.9	3.8	4.5
Non-Metallic Mineral Products	2.1	1.2	0.0
Metal & Metal Products	7.2	2.4	3.7
Machinery & Equipment	7	1.2	6.1
Other Industries	8.8	0.9	0.7
B. ALL INDUSTRIES	8.2	2.6	4.2

(a) Derived by eliminating any sample biases by industry or region.
(b) The impact on value added excludes labor-related costs which reduce profits by an identical amount leaving value added unchanged.

national exports of manufactured goods as a consequence of power shortages is about 4.2 percent of total exports. This translates into an approximate reduction in exports of about $75 million in hard currency.

The study also estimates (Exhibit 3-12) that the cost of load shedding to industry range from a low $0.29/kWh for textiles to a high of $1.77/kWh for the machinery and equipment industry, with an average cost of approximately $0.50/kWh. In contrast, under situations of uncontrolled load shedding (i.e., outages with no advance notification) the average cost to industry (Exhibit 3-13) is approximately 60 percent higher at $0.81/kWh.

In both instances, spoilage cost -- i.e., damage to machinery and goods -- is a significant component of total cost, accounting for over 60 percent of total direct cost, and about 15 percent of total outage cost. At first glance it is surprising that even in the case of load shedding, this cost component is so high. The primary reason for this appears to be that uncontrolled-announced deviations from the posted load shedding schedule occur frequently.

Long-Run Costs to the Economy

Exhibit 3-14 indicates that individual electricity users have resorted to substantial self-generation to mitigate losses from unreliable power supplies.

The study estimated that the total cost per kWh of self-generation ranges from a low of $0.14/kWh to a high of $0.74/kWh. In contrast, WAPDA's systemwide average long-run marginal cost of supply is estimated to be approximately $0.076/kWh. In other words, WAPDA's economic cost of supply is between two-and-ten-fold lower than the cost incurred by industry. The extent of this divergence provides some indications of the resource costs to the economy because of this inefficiency.

3.3 OTHER COUNTRIES

This section summarizes the results of several other developing country studies which have attempted to develop estimates of the costs of electricity shortfalls. The results of

Exhibit 3-12

Components of Loadshedding Cost per Kilowatt Hour by Type of Industry and Process

		Direct Cost			Adjustment Costs				Total Loadshedding Cost	
		Spoilage Cost	Net Idle Factor Cost	Total Direct Cost	Labor Related Cost	Capital Related Cost	Timing Related Cost	Total Adjustment Costs	Rs /kWh	$/kWh
A	BY INDUSTRY GROUP									
	Food, Beverages & Tobacco	8 25	0 89	9 14	0 20	0.50	0 10	0.80	9 94	0 68
	Textiles	1.33	2.70	4 03	0.09	0.13	0.04	0 26	4 29	0 29
	Wearing Apparel & Footwear	2.40	0.68	3.08	1 97	6 38	0 00	8 35	11.43	0 79
	Wood & Paper	7 64	3 31	10 95	0.14	0.24	1 40	1.78	12 73	0 87
	Chemicals & Petro-Chemicals	7.83	2.12	9 95	0.32	0 31	0 00	0 63	10 58	0 73
	Non-Metallic Mineral Products	0.04	0.51	0.55	0 30	3.40	0 00	3 70	4.25	0 29
	Metal & Metal Products	3.71	2.45	6.16	0.20	0.20	0 06	0 46	6 62	0 45
	Machinery & Equipment	15 94	3 34	19.28	0.77	5.47	0.19	6.43	25.71	1.77
	Other Industries	4.14	0.65	4.79	0 23	0.25	0.00	0 48	5 44	0 37
B	BY PROCESS									
	Batch-Making	2 51	0.71	3 22	0.12	0 36	0 08	0.56	3 78	0 26
	Continuous	9.90	9.89	19.79	0 56	1.68	0 00	2 24	22 03	1 51
C.	TOTAL SAMPLE	3.64	2.19	5.83	0.21	0 56	0 07	0.84	6 67	0 46

a. Cost of additional overtime and/or shifts.
b. Cost of generators and/or more intensive operations of machinery.
c. Cost of changes in shift timings or in working days.

Exhibit 3-13

Components of Unplanned Outage Cost per Kilowatt Hour by Type of Industry and Process (Rupees)

	Spoilage Cost	Direct Cost		Adjustment Costs			Total Unplanned Breakdowns Cost per	
		Net Idle Factor Cost	Total Direct Cost	Labor[a] Related Cost	Capital[b] Related Cost	Total[c] Adjustment Costs	Rs./kWh	$/kWh
BY INDUSTRY GROUP								
Food, Beverages & Tobacco	26.94	1.88	28.82	1.01	0.44	1.45	30.27	2.08
Textiles	1.90	3.06	4.96	0.23	0.09	0.32	5.28	0.36
Wearing Apparel & Footwear	8.01	1.81	9.82	1.88	1.26	3.14	12.96	0.89
Wood & Paper	26.95	3.94	30.89	0.69	1.42	2.11	33.00	2.27
Chemicals & Petro-Chemicals	6.23	10.75	16.98	0.59	1.32	1.91	18.89	1.30
Non-Metallic Mineral Products	0.23	1.96	2.19	0.43	1.80	2.23	4.42	0.30
Metal & Metal Products	7.85	4.66	12.51	0.35	0.55	0.90	13.41	0.92
Machinery & Equipment	13.79	8.40	22.19	6.35	5.74	12.09	34.28	2.35
Other Industries	6.19	1.11	7.30	2.20	0.50	2.70	10.00	0.69
BY PROCESS								
Batch-Making	2.69	3.67	6.36	0.42	0.28	0.70	7.06	0.48
Continuous	23.66	9.60	33.26	1.22	2.48	3.70	36.96	2.54
TOTAL SAMPLE	6.40	4.03	10.43	0.62	0.68	1.30	11.73	0.81

a Cost of additional overtime and/or shifts.
b Cost of generators and/or more intensive operations of machinery.
c Cost of changes in shift timings or in working days.

Exhibit 3-14

Extent of Self-Generation of Power During Outages and Generator Costs per Kilowatt Hour by Type of Industry and Process

	Percentage of Sample Firms Using Generators (%)	Average Extent of Substitution of WAPDA by Generators (%)	Total Cost per KWH of Self Generation		Percentage of Sample Firms Planning to Invest in Generators (%)
			(Rs/kWh)	($/kWh)	
A. BY INDUSTRY GROUP					
Food, Beverages & Tobacco	9	83	3.13	0.21	17
Textiles	8	82	2.68	0.18	11
Wearing Apparel & Footwear	19	84	7.30	0.50	11
Wood & Paper	6	93	10.76	0.74	16
Chemicals & Petro-Chemicals	17	81	5.32	0.37	12
Non-Metallic Mineral Products	8	98	2.92	0.20	6
Metal & Metal Products	9	88	1.97	0.14	19
Machinery & Equipment	19	85	6.63	0.46	23
Other Industries	22	75	9.85	0.68	11
B. BY PROCESS					
Batch-Making	10	81	2.80	0.19	14
Continuous	16	86	5.76	0.40	21
C. TOTAL SAMPLE	12	83	3.42	0.23	16

these studies are presented in Exhibit 3-15. With the exception of India, Pakistan, Egypt and Bangladesh, the countries listed in the exhibit have not been subject to shortfalls in generation capacity.[21] Thus, the majority of study estimates in Exhibit 3-15 were developed for the purposes of evaluating projects that improve local area reliability as a result of reinforcing or rehabilitating the sub-transmission and distribution network. As a consequence most of these estimates of interruption costs (sometimes also referred to as outage cost, failure costs, or cost of non-supply) relate to unplanned outages.

Electricity interruption costs reported in Exhibit 3-15 are typically in the range of \$0.50/kWh to \$5.00/kWh. However, certain individual customers will have costs substantially higher than the \$5 estimate. With average electricity tariffs in the range \$0.05/kWh to \$0.12/kWh, this data indicates that in the short-run, customers would be willing-to-pay between five to one hundred times the average tariff, to avoid the adverse effects of power supply interruptions.

By way of contrast, estimates of customer interruption costs in the U.S. and Canada are summarized in Exhibit 3-16.[22] The ranges in Exhibit 3-16 are indicative of the different estimates reported in the literature. These ranges are meant to capture variation from several sources including: (1) outage characteristics such as timing, magnitude, duration, advance notification, (2) different segments within a customer class, and (3) severity of an energy deficiency as measured by the percentage of normal energy consumption that a user is called upon to curtail.

Point estimates which reflect the central tendency (median value) for each segment in Exhibit 3-16 are: \$1.00/kWh for the residential segment, \$5.00/kWh for the industrial

21 Because of foreign exchange restrictions during the period 1978-1982, the Jamaica Public Service Company suffered from a shortage of spare parts for its large thermal generating stations. As a result, the system was frequently unable to satisfy demand, resulting in widespread outages over that four year period. However, this situation has since been rectified, and most service interruptions that customers now face are related to network disturbances.

22 Measurements of interruption costs have also beeh attempted in Sweden, Finland, France, Switzerland, Norway, United Kingdom, U.S.S.R., New Zealand, Australia, and Japan. Some of these results are summarized in references [31], [36]. [34].

Exhibit 3-15

Costs of Power Outages in Selected Developing Countries (1987 US$)

Country	Sector(s)	Type of Shortfall	Cost of Outage	Overall Measurement Approach
1. Bangladesh [50]	All	Unplanned outages	1.00 $/kWh	Based upon estimates reported in other studies
2. Brazil [23]	1. Households	"	1.95-3.00 $/kWh	Wage rate reflects lost leisure
	2. Industry	"	1.77-8.42 $/kWh	Survey to assess idle factor costs, and spoilage
3. Chile [20]	1. Households	"	0.53 $/kWh	Annuitized value of household appliances made idle
	2. Industry	"	Range: 0.25-12.00 $/kWh Central Tendency 1.50-6.00 $/kWh	Input-output model

Exhibit 3-15 (continued)

Country	Sector(s)	Type of Shortfall	Cost of Outage	Overall Measurement Approach
4. Egypt [3]	Industry	Unplanned outages	0.40 $/kWh	Input-output model
5. India [26], [51]	1. Industry	Controlled load shedding	Annual cost ranges from 1 to 3% of GDP (1.5 to 3 billion dollars annually)	Survey to determine production loss attributable to power short-fall
	2. Agriculture	"	Sector production loss of 2.3% in 1983-84	"
6. Jamaica [39]	Industry	Unplanned outages	1.25 $/kWh	Estimate of fraction of value added lost
7. Pakistan [43]	Industry	Controlled load shedding	Range: 0.26-1.77 Average: 0.46 $/kWh	Survey to determine idle factor costs, spoilage, restart costs
		Unplanned outages	Range: 0.36-2.54 Average: 0.81 $/kWh	"

Exhibit 3-15 (continued)

Country	Sector(s)	Type of Shortfall	Cost of Outage	Overall Measurement Approach
		Controlled and Uncontrolled load shedding	$350 million in 1984-85	(1) + (2)
8. Paraguay [46], [47]	Residential	Unplanned Outages	$.87/kWh	Consumer surplus loss
9. Taiwan [31]	Industry	Unplanned Outages	0.06-2.27 $/kWh	All value added lost
10. Tanzania [42]	1. Households	Unplanned Outages	0.50 $/kWh	Cost of obtaining substitute services from alternate means
	2. Industry	Unplanned Outages	0.70-1.40 $/kWh	Some fraction of value added cost depending upon plant capacity utilization
	3. Commercial	Unplanned Outages	1.00 $/kWh	Assumed equal to average cost to industry
	4. All sectors	Unplanned Outages	0.70-1.10 $/kWh	Weighted average of 1 through 3 above

sector, and $10.00/kWh for the commercial sector. These estimates are on the conservative (i.e., low) side.[23]

Exhibit 3-16

Outage Costs as Reported in U.S. and Canadian Studies (1988 Dollars per kWh)

Customer Segment	Capacity Related Interruptions	Energy Deficiency 5%	10%	20%	25%	30%
Residential	50¢ - 5$	1¢	2¢	7¢	-	20¢
Industrial	2$ - 20$	6¢ - 1$	20¢ - 5$	30¢ - 8$		-
Commercial	5$ - 35$	3¢	10¢	50¢	-	3$

Source: References [31], [36], [34]

4. CONCLUDING REMARKS

In developing countries, the power sector is a vital component of the basic infrastructure. Industrial productivity, economic growth, as well as social development, all depend to varying degrees upon the performance of this sector. Unfortunately, many developing nations are plagued by power shortages. Inadequate power supplies today in countries such as India and Pakistan are choking more rapid economic growth. In addition to slowing industrial growth, power shortages can result in increased imports and a decrease in exports, with the potential for further adverse impacts on income and employment generation.

For example, in India and Pakistan, lost industrial output caused by power shortages is estimated to have reduced GDP by about 1.5 to 2 percent. These estimates are on the

23 This information can be used to develop a systemwide weighted average outage cost. For example, in a system where the class shares of sales are 35 percent residential, 30 percent industrial, and 35 percent commercial, the systemwide average outage cost would be $5.35/kWh of unserved energy.

conservative side. In the case of India, they do not included costs of damage and spoilage. Further, as static and single-period estimates they may grossly understate total costs, since they not reflect income losses in future periods as a result of current income losses. This can happen if further investment in capital stock expansion and in more efficient equipment is retarded because of reduced savings now. If these forces are operative, then the costs of electricity shortages could be significantly higher than the 1.5 to 2 percent of GDP.

In addition, these estimates do not included the value of foregone services associated with electricity consumption in the commercial and residential sectors.

Unfortunately, for many developing countries, the future looks bleak as well. Because of the high capital intensity of the power sector coupled with severe resource constraints, the growth in demand for power is outstripping the ability of such countries to provide adequate supplies. A recent study [27] [14] estimates that if the World Bank's medium forecast of 4.5 percent in real economic growth rate are borne out, then electricity consumption in developing countries will grow at an average annual rate of 6.1 percent over the next 20 years, necessitating an additional 1,500 gigawatts of new generating capacity. This will require investments of $125 billion each year, compared with the $50-60 billion being spent now annually. Most countries are severely strained in meeting todays level of investment. Thus, doubling expenditures is next to impossible. Further, even with modest increases in development assistance and loans, this gap will not be narrowed appreciably [18], [48].

Against this reality, many developing countries will need to confront the problem of managing supply-demand imbalances (shortfalls) in the future. Under such conditions it is essential that the limited capital available be employed in developing the most effective combination of supply enhancing and demand conserving resources.

Low cost supply enhancement options in many instances include network loss reduction, and reduction of unbilled consumption. Whereas transmission and distribution losses should normally be well below 10 percent, in many developing countries losses--technical plus non-technical losses--are well over 20 percent, and in a few cases over 30 percent [52]. Other major supply enhancement options with very short payback and

short lead-time periods include better plant maintenance to increase plant availability and plant efficiency (heat rates).

On the demand-side, several low cost options are potentially available to increase end-use efficiency and to reduce consumption. These include electric motors with variable speed controls, power factor improvements ,and high efficiency irrigation pumpsets, lighting fixtures, and refrigeration and airconditioning equipment [49], [27]. Furthermore, cost effective load management--in particular peak shaving and load shifting to off-peak periods--provide developing country utilities with the potential for realizing significant efficient gains. Unfortunately, the use of such options is the exception rather than the rule. This even though many of the load management technologies are simple, technically proven, and pricing strategies based upon use of these technologies have been successfully implemented in several western nations including France, and the U.S.

Indeed, many U.S. utilities have gone on the record to say that by pursuing an aggressive program of demand management coupled with anticipated supplies to the grid from customer owned cogeneration, and purchases from independent power producers, there is little or no need for them to build any new generating capacity, at least for the remainder of this century.

Developing countries should take steps to promote and integrate the larger cogenerators and consumers with captive generation--present and future--into the grid. The necessary technical issues, as well as regulatory, legal, institutional, and pricing issues need to be resolved, and standard procedures established for such interconnections. In this regard, lessons learnt from the U.S. experience with the "PURPA legislation" provides a good starting point for tailoring such initiatives to specific countries [33].

Further, sooner or later, most developing countries will have to come to grips with the problems created by distortionary pricing and widespread cross-subsidies in electricity tariffs. In significant measure, such practices over the years have further aggravated the already poor reliability picture. In almost all developing countries, electricity provided to residential and agricultural consumers is heavily subsidized. More generally, most

customer segments pay substantially less for electricity than the true resource cost of providing power. For example, it has been estimated that the cost of supplying a unit of electricity to an agricultural user in India is over 14 U.S.¢/kwh, yet such users are typically charged less than 3 U.S.¢/kwh [44].

In Egypt it is reported that average electricity prices are only 40 percent of the economic cost of supply (i.e., the long-run marginal cost (LRMC) [6], [29]). In the case of WAPDA in Pakistan, as recently as June 1986 the average agricultural tariff was only 34 percent of the economic cost of supply, with comparable percentages of 42 percent for residential, and 54 percent for industrial customers.[24]

Such heavily subsidized tariffs have the effect of stimulating electricity consumption beyond economically efficient levels. Furthermore, in most instances electricity prices have declined in real terms. This further stimulates demand. Thus, when tariffs are not closely aligned to the true costs of providing additional power supplies, two reinforcing influences arise. First, there is a substantial amount of "non-economic demand" that is created, i.e., demand which exists simply because the price is subsidized. This demand is wasteful in an economic sense.[25]

Second, the power supplying entity is often unable to recover even the financial cost of operation. Financial losses usually result in severely limiting the utility's ability to properly maintain and operate the existing power system, as well as expand the system for future load growth. If unchecked over a period of time, these inefficiencies get progressively worse, with the utility always in the position of playing catch-up, but continually losing more ground. To varying degrees these forces are at work in most developing countries.

For example, in India with few exceptions most of the State Electricity Boards (SEBs) that have the responsibility for generating and distributing electricity have been incurring financial losses in staggering amounts. During 1986-87, it is reported that average revenues per unit of sales typically ranged between 50 and 70 percent of the

[24] Source: Report of the World Bank Resident Mission, Islamabad.

[25] To this extent some of the present "shortages" are overstated.

average cost of supply, and were as low as 30 percent in one state [15]. Based upon 1986-87 generation of 188 x 10^9 kWh, this implies revenue losses of the order of Rs. 3,200 crores (approximately $2.5 billion at current exchange rates).[26] Furthermore it is estimated that in 1984-85, averaged across all SEBs, the overall rate of financial return on assets was minus 8.1 percent [22].

Raising tariffs to recover financial costs, bringing them in closer alignment with the economic cost of supply, and undertaking the supply enhancement and demand management measures noted previously, will go a long way in eliminating the extent of future shortfalls.

Broadly speaking, situations involving shortages or poor supply reliability due to insufficient generating capacity can be managed in the following ways:

- Establish a new connections policy (queue system) so that new service connections are offered only if there is sufficient generation capability.

- Connect everyone who wants service, but ration the shortfall by pricing mechanisms, or by controlled load shedding.

  Pricing options include interruptible tariffs, demand subscription service, load management tariffs, dynamic pricing etc. [32].

  Controlled load shedding involves managing a deficiency in generation by instituting curtailments in power supply according to a pre-arranged schedule. These curtailments may take the form of rotating of blackouts (i.e., complete loss of service), or stipulated partial reductions in load.

- Ration the shortfall by uncontrolled load shedding. Such unplanned outages represent complete loss of service without any advance notification.

[26] Sales = 188 x 10^9 kWh x 0.70 (this assumes 11 percent station use, and 19 percent technical plus non-technical losses [15], [22]). Furthermore, this calculation assumes an average revenue requirement of 75 paisa/kWh, and an average unit price that is 65 percent of average cost.

In practice the first strategy is seldom used. Uncontrolled load shedding imposes the highest economic costs upon electricity users. Yet, it's incidence is quite common in several developing countries. This can happen if the utilities concerned are typically functioning with little or no operating reserves. Thus, the sudden loss (forced outage) of a generating unit triggers unannounced load shedding. Most industrial users and business enterprises would prefer a proactive shortage management strategy where notification of potential service curtailments -- frequency, timing, duration magnitude -- is posted in advance and these schedules are adhered to closely.

From the perspective of reliability, an efficient shortage management strategy is to employ innovative pricing options, under which at times of system emergencies users essentially sell back part of their demand to the utility in exchange for a bill discount. Such pricing options include interruptible tariffs, demand subscription service, load management tariffs, dynamic pricing, as well establishing prices to encourage the sale of power to the grid by customers with captive generation sets or cogeneration. An optimal shortage management strategy would involve managing all or as much of the supply deficiency as is possible by pricing mechanisms of the type noted above. Any remaining imbalance, can be further managed by controlled load shedding.

Finally, the "private power option" merits serious consideration in developing countries [2]. This would allow for private ownership and generation of electricity for the explicit or primary purposes of selling power to the grid. At present, electric utilities in developing countries are typically owned and operated--and otherwise strongly influenced--by the government. As a consequence, investments required for expanding power supplies represent a significant component of the national budget, typically over 20 percent. Further, in many countries outstanding loans for the power sector already represent over 40 percent of the national debt, thus limiting the government's ability to raise additional funds in the capital markets. Private power producers offer a means for filling the supply-demand gap, by bringing additional financial resources.

In addition, the presence of private power producers should have the effect of enhancing economic efficiency in the production and consumption of electricity since they will bring to bear additional technical and managerial resources. In the long-run,

private enterprises can only function if they are able to recover their costs and a reasonable return on investment. Therefore, the extent of government subsidies will be reduced in tariffs. Furthermore, the presence of private power producers will inject an element of competition into the power markets in developing countries [33].

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FLEXIBLE STRATEGIES FOR LOAD/DEMAND MANAGEMENT USING DYNAMIC PRICING

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Abstract - This paper highlights the need for and the potentially important role of dynamic pricing options in achieving a utility's demand management objectives Such options also offer utilities the flexibility they need to cope with the uncertain and shifting environment they increasingly face The paper describes current developments in and experiences with dynamic pricing

1. INTRODUCTION

Utilities are increasingly using rate incentives for achieving load/demand-side management (DSM) goals In the U S , surveys of investor owned and public power utilities by the Electric Power Research Institute (EPRI) reveal substantial interest and implementation activity in introducing a wide variety of rate designs [9] Most common among such "innovative rates" are interruptible tariffs, time-of-use (TOU) pricing, increasing block rates, and industrial incentive/economic development rates Other rate forms that have emerged include demand subscription service, coincident demand charges, and special rates such as super off-peak pricing, and real time pricing

Many utilities in the U S see innovative rate structures as strategic options to improve their competitive position by offering a choice of such rate options to those customers who are most inclined to meet their energy requirements from alternate energy sources such as natural gas, and cogeneration

—e of this interest can also be attributed to an emerging recognition in the industry that its traditional practice of providing all users with a uniform and very high level of service reliability and at prices prespecified well in advance has major shortcomings For one, this mode of operation is sustainable only by incurring costs that are significantly higher than necessary By introducing dynamic pricing options which can more closely track actual costs, the utility can essentially "unbundle" electric service and offer its customers a range of rate-reliability choices. This tailoring of service should result in a closer matching of customer needs and cost share responsibilities, and therefore in all customers being better off

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Further, there is growing recognition that utility planning and operations today are characterized by substantial uncertainty However, most of today's tariffs are pre-specified well in advance (one or more years), and thus do not provide utilities with an effective means for managing demand under shifting conditions Classical tariffs are inflexible and therefore preclude achieving significant opportunistic gains in short-term efficiency, gains which can be to the mutual benefit of the utility and its ratepayers, and to those consumers who have the capability but are at present not responding under such circumstances because of ineffective price signals By incorporating one or more real time[1] elements into a tariff, it can be made more responsive to utility and customer needs

This paper highlights the need for and potential role of flexible pricing options which offer an efficient means for achieving a utility's load/demand management objectives The focus of this paper is on dynamic tariffs By incorporating real time features within one or more key parameters of the tariff, such pricing options can be tailored to offer the degree of flexibility that is necessary and cost effective for achieving the given demand management objective(s)

This paper is organized as follows Section 2 develops the rationale and role for dynamic pricing. Fundamental to the development of such innovative tariffs is the concept of a utility's short-run marginal cost structure Section 3 briefly defines and illustrates this concept, it also describes how this cost structure can be estimated, and indicates potential applications Section 4 identifies examples of load/demand management strategies that are dynamic and hence flexible, and that are either being used or have been suggested Section 5 contains some concluding observations Finally, superscripts in the text denote reference to a footnote at the end of this paper

2. THE RATIONALE FOR DYNAMIC/FLEXIBLE PRICING

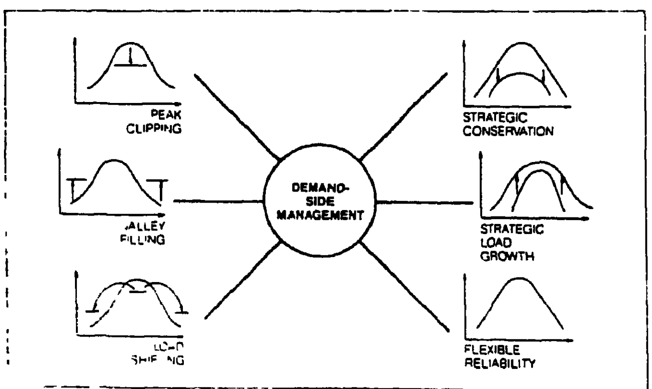
The term dynamic pricing is used in this paper to broadly encompass tariff structures that have one or more elements which are calculated and posted close to the time of applicability. This definition embraces several concepts developed in the pricing literature such as real time (spot) pricing [26], responsive pricing [28], state preference pricing [14], "flexible pricing", and certain forms of "incentive rates", and "economic development rates"

The practical motivation for developing dynamic pricing options can perhaps be traced to the unprecedented cost pressures, competitive challenges, and a highly uncertain planning and operating environment that many utilities face today in their mission to provide an adequate supply of power, reliably and

economically A central component of any strategy for successfully coping with such conditions is flexibility, the ability to quickly respond and cost effectively adapt to changing circumstances, and market conditions For example, in the area of resource planning flexibility means developing a resource strategy centered around a portfolio of flexible resource options that can cope with different futures, rather than a resource plan of unit additions In the area of tariffs and demand management, flexibility means among other things an ability to convey the right signals to consumers that will trigger the desired response Exhibit 1 depicts some typical demand management objectives that utilities may face peak shaving, valley filling, load shifting, strategic conservation, strategic load growth, and flexible reliability [10]

Against this background, one can focus on the inherent rigidity in the most common forms of pricing used today for demand management Specifically, Time-of-Use (TOU) tariffs, and more generally most all other tariffs in place today share one thing in common They are calculated and posted up to a year or more in advance of the time of consumption Therefore, they must be developed based upon the best estimates of the expected values of key stochastic variables, that are likely to prevail in the future

EXHIBIT 1
SOME OBJECTIVES OF DEMAND MANAGEMENT



More often than not, actual conditions turn out to be considerably different than those predicted when the tariffs were calculated (a year or more earlier) Short-term excesses can arise due to unanticipated turn down in load because of economic or other reasons, and due to foreseen events such as the addition of a new generating unit whose capability is large with respect to total system size thereby resulting in excess reserve margins temporarily On the other hand, shortages can arise due to a variety of unpredictable circumstances such as adverse hydrological conditions, fuel shortages, transmission bottlenecks, plant failure, and faster than anticipated economic growth

Under such constantly shifting conditions, pre-determined and static tariffs are likely to convey incorrect price signals, signals that maybe grossly inadequate for the prevailing demand supply balance at any point in time, and may even foster counter productive customer responses

In contrast, under dynamic pricing tariffs are estimated and posted much closer to the time of consumption (hours, days or weeks prior) Furthermore, they have a much shorter horizon of applicability (e g 1 hour, 24 hours, a week, a month, or a quarter) Accordingly, they are updated much more frequently than classical TOU tariffs The update frequency and valid horizon for such tariffs can be determined by three factors (1) the utility's short-run marginal cost structure, sometimes also referred to as its variable energy cost (VEC) structure, (2) electricity usage characteristics of the customers being serviced, especially regarding the potential for being able to be responsive to such cost variations, and (3) the costs and benefits of additional metering, communication, control, and billing required to support such tariffs.

For example, a utility whose generation mix is predominantly thermal and whose cost structure exhibits substantial variation by time-of-day and season may offer a 24-hourly "spot price" based tariff that is updated every 24 hours, or a tariff that is valid for one hour only and is updated every hour On the other hand, hydro-dominant systems that are more likely to be energy constrained might find that a monthly or quarterly update horizon is sufficient to adequately reflect variations in their cost structure that is linked to the stochastic process governing the underlying hydrology

Even thermally oriented systems may wish to smooth out to some extent the real time cost variation and yet offers tariffs that are substantially more dynamic than classical tariffs Some examples of dynamic tariffs in section 4 of this paper suggest that substantial gains in short-run efficiency can be achieved without necessarily having to resort to real time tariffs of the extreme hourly or even 24-hourly update variety

3. VARIABLE ENERGY COST (VEC) STRUCTURE OF A UTILITY

The cost of providing electricity -- generation and delivery -- generally varies with time, location, supply voltage, weather and hydrologic phenomenon, and other system and customer characteristics Real time (spot) prices reflect the price of electric energy based on this short-run marginal cost of production and delivery. A detailed exposition of the theory of spot pricing is beyond the scope of this paper Interested readers are referred to references [24] [26] Briefly, however, a spot price is defined by the following equation

Spot price (¢/kWh) at time

= marginal generation fuel cost at time t

+ marginal generation and network (T&D) maintenance cost

+ marginal network losses at time t

+ generation quality of supply cost at time t

+ network quality of supply cost at time t

The first component is closely related to the familiar "system lambda" The losses component can be significant at times of high demand The last two quality of supply components are negligible except at times when the system

s under stress, i.e., demand is pressing against available generation or network capacity.

The quality of supply components can be approximated in one of several ways (1) the price increase required to balance demand and supply at time t, (2) customer outage cost (i e , the cost of a shortfall to the customer [17]), or annualized capital cost to the utility of installing additional capacity generation or network, as the case may be) to avoid the incremental unit of shortfall Unless a utility is chronically supply constrained or there are transmission bottlenecks, the quality of supply components of a spot price are likely to be negligible However, during critical times this reliability premium can dominate

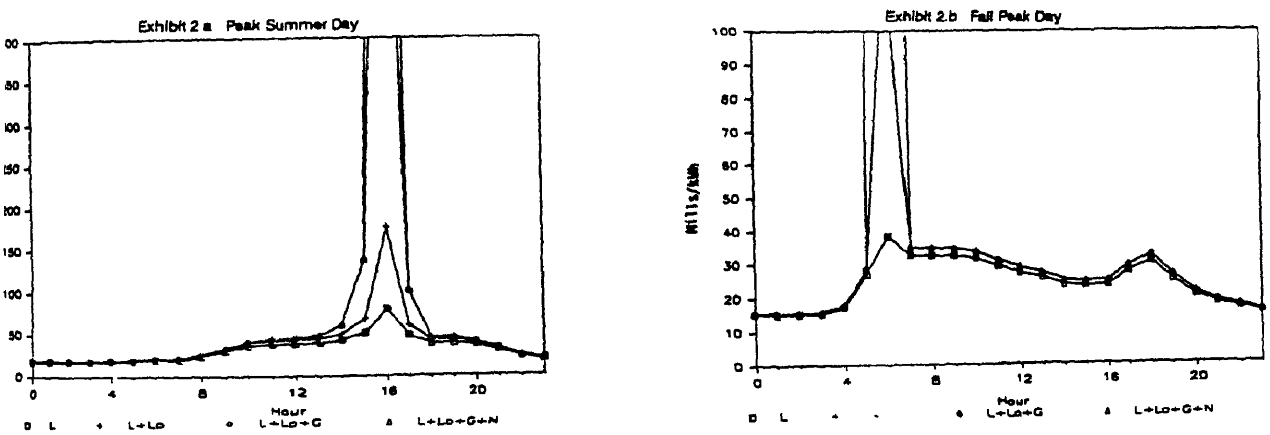
Two further points are worth noting In the theory of spot pricing, there is no demand charge Spot prices are purely an energy rate expressed as ¢/kWh Finally, pure spot prices will generally have to be adjusted upward or downward to achieve revenue reconciliation

The short-run marginal cost structure of a utility can be estimated by performing a variable energy cost (VEC) study A VEC study simulates system operations under different outcomes of key stochastic variables judged to be relevant (e g, loads, hydrology, unit availability, weather, transmission bottlenecks) Such an analysis also provides the necessary insights about the minimum duration sub-periods of interest from the point of view of capturing the major variations in the utility's cost structure

Exhibit 2 highlights typical hourly spot prices for a U S utility during selected days of a year [26] The six sub-exhibits in Exhibit 2 together illustrate that the hourly cost structure can vary substantially by time-of-day, by season, and between a peak day and a typical day Typical summer and fall day cost profiles are depicted in Exhibits 2c 2d, and 2f To illustrate, on a typical summer day costs rise during the morning hours, reach a peak around noon, stay constant until about 4 p m and then decline to the minimum cost by the early morning h ... ast the typical winter day costs profile has a

EXHIBIT 2

VARIATION IN HOURLY COST STRUCTURE BY SEASON



Legend L denotes generation fuel and variable maintenance costs, L_o denotes network losses, G denotes generation quality of supply costs, and N denotes network quality of supply cost

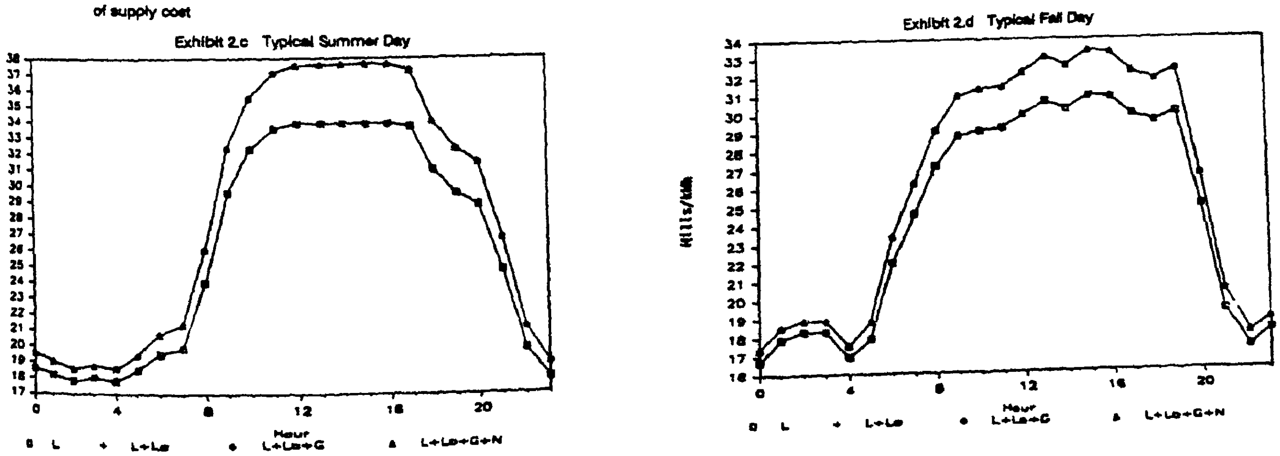
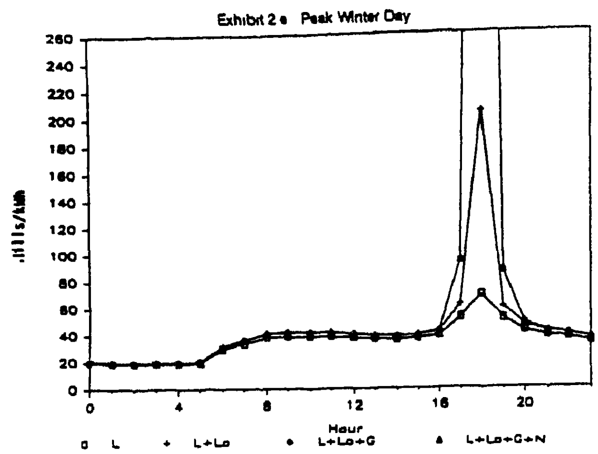
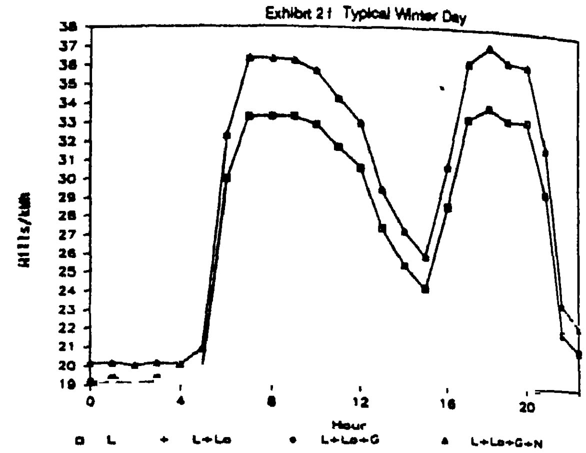


EXHIBIT 2 (CONTINUED)





Legend L denotes generation fuel and variable maintenance costs, L_0 denotes network losses, G denotes generation quality of supply costs, and N denotes network quality of supply cost

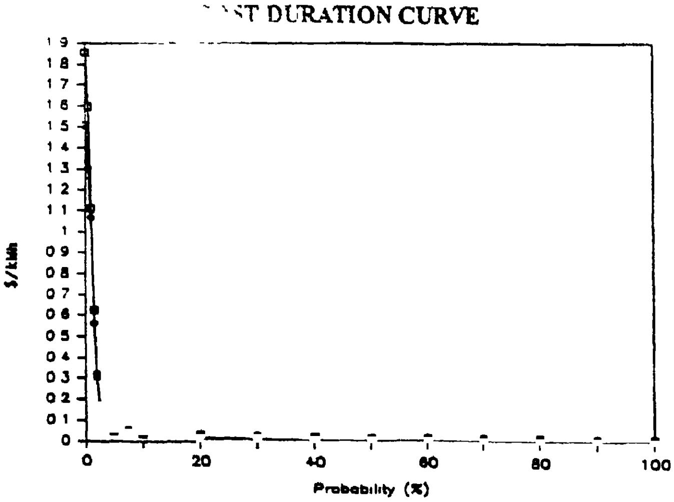
different peaking pattern The generation and network quality of supply components of typical day costs are zero On these days the short-run marginal cost is determined largely by the generation fuel and variable maintenance (component L in Exhibit 2), and by losses (component L_0 in Exhibit 2) In contrast, the peak day cost structures (Exhibits 2a, 2b, and 2e) do reflect costs related to generation and network supply reliability Indeed, during the peak hours on such days, the quality cost components G and N dominate the other two costs

For hydro dominant power systems the corresponding hourly spot price trajectories are likely to exhibit a "sleepy" and monotonously flat profile with significant variations occurring only on a seasonal or annual basis, reflecting the underlying hydrological variation

The results of a VEC study can also be succinctly summarized and presented as a cost duration curve An annual cost-duration curve for a U S utility is shown in Exhibit 3 Cost duration curves synthesize the short-run marginal cost variation over a given period of time, and present the data in a format that is easily interpreted probabilistically Just as the familiar load duration curve defines the percentage of time that load exceeds different levels, a cost duration curve defines the percentage of hours that the short-run marginal cost exceeds different values These curves provide valuable insights

EXHIBIT 3

COST DURATION CURVE



- The integral of such a curve over its domain generates an average spot price over that time period For example, suppose that the expected cost of the cost duration curve in Exhibit 3 is 10¢/kWh This value can be used for establishing a tariff for a certain customer class where signaling intra-period variation in cost is not cost-beneficial

- The cost duration curves also provide valuable information for tailoring a menu of tariffs that offer large users a choice of service at different prices, but with a commensurate level of reliability which would be specified in advance For example, if a user wants a stable price of 6¢/kWh this curve can be used to estimate the reliability of service that he must put up with

  Suppose that the integral of the cost duration curve in Exhibit 3 between 3 percent probability (spot price of 20¢/kWh) and 100 percent probability (spot price of 5¢/kWh) is 6¢/kWh Then a contract can be structured which provides the user with a stable price of 6¢/kWh but also stipulates that the service could be interrupted up to 3 percent of the time However, the user could override the interruption clause by paying the prevailing spot price, which Exhibit 3 estimates as ranging between 20¢/kWh and $1 90/kWh

  Alternately, the user could specify the desired level of service reliability (i e , the maximum interruption time) and the cost duration curve can be used to estimate the corresponding price of service, quoted either as a stable price or as a range

- Cost duration curves can also be developed to assess the cost structure in select future years of the planning horizon. Such an analysis -- when undertaken for a future year (or years) when new plant additions are planned under the optimal system expansion -- essentially provides estimates of the long-run marginal cost (LRMC) as well.

This information can be used for designing those tariffs where it is considered desirable to reflect long-term price signals

-us, a variable energy cost study which quantifies the cost structure in . ..r term as well as in select future years provides valuable information for designing an effective variety of tariff options, some of which are meant to enhance short-term economic efficiency and others which stress long-term signals Larger users, in particular, may elect to place portions of their load in different tariffs

4. SOME EXAMPLES OF DEMAND MANAGEMENT USING DYNAMIC AND FLEXIBLE PRICING OPTIONS

There are several dynam... tariffs in operation worldwide that have a "real time flavor in that th... ... more elements of the tariff that are estimated and posted much closer to the time of consumption and are updated more frequently than the classical TOU or other tariffs Major features of some of these tariffs are highlighted in this section (see Exhibit 4)

In France, Electricite de France (EDF) reports success with the Peak Day Withdrawal (PDW) option tariff [13] The peak period is typically distributed over a large number of hours (18 hr/day) but for only a small number of days (2?) per year Furthermore, such days are not easy to predict with any degree of certainty in advance On such days, the energy price variation between peak & off-peak is around 10 1 Under this tariff, EDF announces in real time (only one half hour in advance) that the given day is a peak day However, in order to facilitate longer term planning decisions by subscribers, other parameters of the tariff such as the 18 hour duration of the peak period, and the peak to off-peak differential in the energy prices are specified beforehand

EDF has offered this tariff to industrial users since 1982 and since 1985 to residential users as well About 1 100 industrial users and approximately ...000 domestic users are ... on this tariff EDF reports load reductions of up to 760 MW during its winter peaks, on a contracted industrial load of about 1,300 MW and a comparable reduction of 200 MW from domestic customers Many industrial customers with dual fired heating systems, with facilities that can modify or interrupt their production process (e g, steel production), or those with processes that have intermediate storage (e g., chlorine electrolysis) have selected this tariff

Residential users who have opted for this tariff are generally among those who have dual fuel heating equipment -- typically a heat pump which is used during off-peak hours in the year, and an oil-fired boiler which in used when the price of electricity is high in peak hours However, some domestic users who currently subscribe to this tariff do not have a dual fired heating system They respond simply by reducing consumption EDF plans to have about 2.5 million households on this tariff by 1995, of which, only a third are expected to have such dual fired systems [18].

Finally EDF's experiment with its "modulatable" tariff option for bulk power users (> 10 MW) represents a step toward implementing spot pricing Energy prices vary in four periods of fixed duration, as opposed to two periods under the PDW option Whereas the energy prices in each period are posted well in advance, the definition of each period's timing is flexible and defined in real time by EDF

Of special relevance to energy constrained hydro dominant systems are two interruptible tariffs in Sweden that have more real time aspects than the French PDW tariff These are designed to help achieve more efficient operations in a situation that is presently marked by a temporary surplus in supply but with a long-term trend which spells a deteriorating annual load factor The tariffs are targeted to large industries, office and apartment buildings, and those users with dual fired boilers (electric-gas or electric-oil) Under one tariff, supply is guaranteed for 8,000 hrs/annum on average over a five year contract period For users who can live with potentially lower reliability, a second tariff guarantees only 15,000 hour of supplies in five years

In both cases, any "surplus" power -- in months when waterflows are high -- is offered at the prevailing "low" marginal cost These interruptible tariffs are dynamic in that information on the periods of surplus and the cost of such surplus is posted only when actual conditions are known The Swedish utilities involved also offer bonuses for customers to install dual fired systems for this purpose [4].

Britain's South Eastern Electricity Board is testing a system whereby the British Broadcasting Company (BBC) transmits electricity prices to households in Brighton every five minutes over regular power lines The signal is picked up by computerized switch boxes that homeowners can pre-set to regulate the flow of electricity to appliances according to the price they want to pay. For example, the system can keep a customer from using an appliance after the utility has switched to expensive peak load price [30]

In addition, the Central Electricity Generating Board (CEGB) offers several innovative interruptible tariffs [22] and has conducted a real time pricing experiment with industrial users In order to achieve more control over its peak loads the CEGB also offers TOD tariffs for very large bulk supply customers in conjunction with an optional interruptible tariff to be effective during the potential peak warning (PPW) periods [1]

Since 1984, Ontario Hydro in Canada has offered optional incentive rates [2] These dynamic tariffs are available to large industrial customers who are prepared to commit to an additional load of at least 3,000 kW The design philosophy underlying these dynamic tariffs emanates from Hydro's expected system condition for the next several years. Through the mid-1990s, available baseload generation is likely to exceed primary demand plus firm export obligations for over 1,500 hours annually, primarily in the off-peak periods of spring, summer and fall (April through November) This excess is expected to peak in 1992 at around 10,000 GWh/annum However, substantial volumes -- in excess of 5,000 GWh/annum -- are expected to be available through the year 1995 Thus, the intent of the optional dynamic tariffs is to encourage incremental uses of the Company's surplus baseload capacity in the short-run, without compromising long-run economic efficiency [20]

Exhibit 4

Major Features of Some Traditional Pricing Options vs Dynamic Pricing Options for Load/Demand Management

Option	Cost Structure/ Valid Horizon	Number of Rating Period(s) Over Valid Horizon	Specification of Duration of Rating Period(s)	Timing of Activation of Rating Period(s)
1 Classical 1-Part Energy Tariff	PS	1 or more	PS	PS
2 2-Part Maximum Demand Charge Tariff	PS	2 or more	PS	PS
3 2-Part TOU Tariff	PS	2 or more	PS	PS
4 Coincident Demand Charges	PS	2	RT	RT
5 Interruptible Tariffs and Demand Subscription Service				
• Standard contract with high cost penalty for failure to comply, based upon ad hoc considerations or predetermined expected spot price	1 Basic Tariff PS 2 Penalty PS	1 or more 1	RT RT	RT RT
• Override penalty provision based upon prevailing spot price	1 Basic Tariff PS 2 Penalty RT	1 or more 1	RT RT	RT RT
6 Dynamic TOU Tariffs				
• EDF's Peak Day Withdrawl Option Tariff	PS	2	PS	RT
• EDF's Modulatable Tariff Option	PS	4	PS	RT
7 Sweden's Dynamic Interruptible Tariff	1 Firm Purchase Component PS	1 or more	PS	PS
	2 Non-Firm Purchases RT	1 or more	RT	RT
8 Ontario Hydro				
• Intermittent Power	PS	up to 50	RT	RT
9 Real Time Pricing				
• Seasonal Update	Next season	1 or more (e g , hourly, 4 periods per day)	PS	PS
• Monthly Update (e g , Ontario Hydro's Monthly Power Tariff)	RT/Next month	1 or more	PS	PS
• Daily Update (e g , PG&E)	RT/Next 24 hours	24	PS	PS
• Hourly Update	RT/Next hour	1	PS	PS

PS - denotes that information element is pre-specified at the time the tariff is posted, typically a year or more in advance for options 1 thru 7 and its valid horizon is typically a year or more

RT - up-to-date calculation and/or posting of information

Hydro also recognizes that its current outlook of the [illegible] and supply balance is also subject to uncertainty To prudently [illegible] exposure vis-a-vis any over commitment of loads to dynamic tariffs that reflect the utility's short-run marginal cost structure, the company has imposed an overall ceiling of 1,000 MW for all loads under the incentive tariffs In addition, total load under incentive rates that involve long-term commitments (i e, two years or more) of pre-set rates is at present limited to 500 MW The balance of sales will be under special condition rate classifications. In particular, under the Intermittent Power and Monthly Power tariffs described below, rates and availability of power reflect up-to-date system conditions Thus, the "current-provisions" that characterize such dynamic tariffs provide Hydro and all its ratepayers an effective hedge against an uncertain future and yet an effective means of enhancing short-run economic efficiency without jeopardizing long-run efficiency objectives

Ontario Hydro's "Intermittent Power" tariff, is a form of dynamic interruptible tariff where service is available for a minimum of 1,500 hours per year, in continuous segments of three hours or more at a time Intermittent power can be recalled at any time If it is recalled within a three hour period, the elapsed time does not count toward the minimum guaranteed available hours. Rates in 1987 are 1.3¢/kWh and the contract is renewed annually when the rate and availability parameters are updated[3] The 1987 rate of 1.3¢/kWh covers incremental cost of power production and provides a small contribution to overhead as well.

Under Ontario Hydro's "Monthly Power", tariff service is available continuously from the months of April through November This rate is calculated and posted in real time based on an up-to-date forecast of system production cost about a week in advance of the month of delivery However, to facilitate user decisions and planning Hydro has provided a non-binding forecast which indicates that during the period 1987-1991, monthly power rates are expected to be in the range 2 0¢ to 2 6¢/kWh Whereas the contact is renewable over a five year period, the maximum term is three years at present

Since Monthly Power rates apply during peak and off-peak hours, they represent a blend of low production cost off-peak power with a number of higher production cost hours The weighted average cost is lower than the cost of year-around firm power Therefore to protect itself, there is a minimum requirement for off-peak consumption to ensure a reasonable balance of on-peak and off-peak costs

A special situation rate which reflects Ontario Hydro's short-run spatial marginal cost structure is for service from its Bruce nuclear plant Because of projected transmission bottlenecks thru the year 1990, Bruce energy cannot be evacuated for a substantial portion of time to the major load centers in the Province of Ontario The Bruce Energy Centre tariff is available to loads in the immediate vicinity of the plant and only during such periods of locked-in energy The rate is between 1¢ to 2¢/kWh[4] and depends upon the customer's pattern of use Contract terms call for termination of this rate by 1990 when it is estimated that additional transmission facilities will be in service Standard rates will be phased in over a two year period, after the special rate is discontinued

A review of program history indicates that under the Monthly Power Tariff, Ontario Hydro sold about 101 GWh in 1985, and 115 GWh in 1986 to two customers Hydro forecasts sales of 363 GWh and 108 MW in 1987, and 229 GWh and 82 MW in 1988

In the U S , the most common form of dynamic pricing practiced today is typified by interruptible tariffs and innovative variants thereof Under an interruptible tariff, notification of a call for interruption is undertaken in real time This represents a substantial dynamic enhancement of a TOU tariff Whereas the customer is told beforehand how many rating periods there are, and the prices during each period are prespecified, the utility announces in real time which rating period is in effect at any point in time Certain rating periods either have an infinite price (if load must be curtailed), or a price equal to the override option price.

For example, San Diego Gas & Electric (SDG&E) Company has recently offered an interruptible tariff with an over-ride provision at a cost of $8 25/kWh on-peak. The utility remotely switches on and off an electronic meter on the customer's premises to register the appropriate rate At the same time this is done the customer is informed of the switch There is no advance warning. In exchange, SDG&E provides substantial discounts on energy during semi-peak and off-peak periods [19]

San Diego Gas & Electric also offers an optional tariff to large users under which the monthly demand charge is based upon the customer's demand coincident to the utility's monthly system peak No advance warning is provided about the timing of the system peak Such a coincident demand charge tariff is a form of dynamic pricing.

As another example, Pennsylvania Power & Light (PP&L) proposed eliminating the demand charge for some of its largest industrial customers for up to two days a week These "demand charge-free days" are supposed to serve as an incentive for customers to shift load and offer the utility an opportunity to boost sales, use up excess generating capacity, and eventually broaden its industrial and commercial base The program is designed to inform participating customers on the day prior that the next day will be demand-free [7] This announcement would be contingent upon a calculation that the utility performs which indicates by 3 pm on a given day that the projected cost of generation on the next day will be lower than the rate schedule charges The utility's Vice President noted that this concept of demand-free days represents "moving a little bit in the direction of real time pricing"

Southern California Edison's Super-Off-Peak (SOP) rate represents an example of a hybrid rate It is essentially a classical TOU-type static tariff in that the rating periods and cost structure are pre-determined and pre-specified well in advance However the rate differentials between peak and off-peak are much steeper than normally seen in TOU tariffs, and that are typical of more dynamic tariffs Furthermore the SOP rate has a 4-hour peak period instead of the 6-hour peak under the milder TOU tariff [8]

To illustrate further, during the summer peak period the demand charge on-peak is $8/kW/month under the SOP rate, versus $3/kW/month under the TOU rate Energy charges under the two tariffs are 21¢/kWh versus 13 8¢/kWh In the summer off-peak period, the demand charge is identical under both tariffs ($0.50/kW/mo) However, energy charges are 5 9¢/kWh under the TOU tariff and range from 3 01-4 9¢/kWh under the SOP rate Thus energy price differentials between off-peak and peak periods in the summer are of the order of 2 under the milder TOU tariff, whereas they are of the order of 5 under the SOP rate

In the U S real time pricing principles have guided short-term economy interchanges and non-firm wholesale power sales since the mid-1980's These transactions which can have horizons as small as 30 mts. to an hours, take place extensively between utilities and power pools At the retail level, several U.S utilities are presently offering experimental tariffs that are based upon the concept of real time pricing. Most notably, such programs are underway at Detroit Edison, Pacific Gas and Electric (PG&E), and Southern California Edison (SCE), for industrial and commercial users

PG&E's spot price tariff is being tried by three industrial users with a total load of 10 MW. Each afternoon around 3 pm the utility estimates and communicates 24-hourly spot prices for each hour of the next day Typically, the peak to off-peak differentials are substantially higher than under classical TOU tariffs For example, on a recent day in 1986, PG&E's quoted spot prices ranged from a low of about 2¢/kWh to a high of 20¢/kWh In

comparison, under PG&E's TOU rate these customers would have to pay about 6 5¢/kWh off-peak, 9.3¢/kWh during shoulder hours, and 11 5¢/kWh on-peak [2], [5] [5]

At Detroit Edison, two major steel companies and an automotive manufacturer representing a total of about 200 MW of load are under the experimental tariff which has built a spot pricing scheme into an economic development rate Customers under this rate pay a minimum of 4 1¢/kWh for electricity use that exceeds prior levels by 1 MW or more, or for loads not previously served However, when the utility's marginal cost of generation exceeds 3 8¢/kWh, the customer is charged the actual cost of generation plus a 1 0¢/kWh adder [5] [6]

The first residential application of the dynamic pricing concept in the U S is being tested by Georgia Power Company [5] The utility has developed a four-tier interval rate guaranteeing that at least 40 percent of the time the price will be 0 5¢/kWh; 40 percent of the time it will be 2 5¢/kWh, 19 percent of the time it will be 9.5¢/kWh, and 1 percent of the time it will be 18¢/kWh In other words 80 percent of the time the rate will be under the Company's standard residential rate of 5.5¢/kWh Information on which rating period is in effect is transmitted in real time via a two-way communication system which also brings energy management, banking, shopping, TV, videotext news and other services into the home, largely through the customer's existing telephone and television system

Customer Response and Acceptance

The most widescale implementation of dynamic pricing can be found in France EDF, a winter peaking utility has been extremely successful in modulating its winter daily load curve because of the combined effect of its classical TOU tariffs that are based upon long-run marginal costs, as well as its more recent and optional dynamic tariffs [13] The Swedish dynamic tariffs described above are of more recent vintage However, it is reported that customers have responded favorably

Data on customer response to real time pricing experiments is generally ·chy and anecdotal This is because such tariffs have been in-place for a relatively short period of time and customers on such tariffs are still learning to adapt and respond to the price variations. However, the signs are encouraging judging from the limited data on participants' responses For example, because of a stiff demand charge under classical TOU tariffs, a steel manufacturer in the U S stopped its smelting operations and imported the refined product for further processing. However, since the company has switched to a real time tariff, it operates the smelters when the spot prices are sufficiently low [22]

A commercial office building in California has responded to real time pricing by taking the following control actions. Air conditioning chillers are started one hour earlier (at 5 00 a.m.) to pre-cool the building for the day In the afternoon, around 1 00 to 2·00 p m., when spot prices are typically high, it executes the demand limiting algorithm on its energy management system (EMS), and then later shuts down the second chiller to coast through the rest of the day [12], [3].

A hospital in California has been responding to real time pricing by shaving its peak load by turning on its backup generators when the spot price of power exceeds the cost of running their emergency generator by 20% [3].

A leading air products manufacturer is reported as having being able to effectively adjust its production process in response to half-hourly spot prices and reduce its electricity bill [22]

A manufacturer of office furniture employing nearly 1,000 production workers and administrative staff has responded to real time pricing by undertaking control actions to shave its peak load during periods when the spot prices are high Such actions are reported to include turning off battery chargers for their electric vehicles, shutting down some individual air conditioning units, and cutting down on inessential lighting The company is also reported to be considering overcharging its ice storage system at night when it expects high prices next day [3]

Generally speaking, customer responses to dynamic tariffs will vary upon the specific situation confronting each The preceding discussion illustrates that such responses include load interruption, temporary use of self-generation, load modification by-resche... of some activities, exploitation of in process storage, load shifting by employing thermal storage or pre-cooling[7], temporarily switch to alternate fuels where such capability exists, and in some instances simply a reduction in consumption when prices are high. It is worth noting that such responses to dynamic tariffs are also typical of the actually recorded responses of industries in Europe and in the U S to the more rigid and classical peak load tariffs [15] The advent of computer based energy management systems now offers customers a quicker response capability to dynamic tariff forms.

An issue of relevance relates to customer acceptance of dynamic pricing forms where prices themselves are posted in real time, as opposed to forms where prices are known well in advance but the rating period is activated in real time For most customers to take control actions that require significant capital expenditures and/or disruption of normal work patterns -- e g., installation of thermal energy storage, process modification, rescheduling workshifts -- it is necessary to know the likely levels and patterns of price variations for at least a year into the future if not more In this sense, the classical TOU tariffs may be advantageous since they are pre-specified well in advance However, bec[illegible] the rating periods for such tariffs tend to be too long, thus ..ing much of the incentive to shape load in closer alignment with the utility's cost structure

On the other hand many customers are leery of the price extremes that characterize some forms of dynamic rates. For such users who may represent a substantial part of a utility's customer base -- e g, large residential users, and small to mid-size commercial and industrial users -- the best form of dynamic tariffs may be those where price menus are pre specified, i.e., prices for each of all possible day types or system conditions -- defined perhaps by an actual outcome of observable system parameters such as temperature, water conditions, and other system operating conditions -- and for rating periods within each day type The utility announces in real time which day-type is operative This structure underlies many of EDF's

dynamic tariffs, the Swedish tariff, the Georgia Power residential real time price experiment, and the Southern California Edison Company real time pricing experiment By posting price menus in advance, and perhaps providing users with a non-binding forecast of the probabilities associated with different day types being operative, users may have sufficient information to facilitate longer term planning decisions related to electricity consumption

5 CONCLUDING REMARKS

Dynamic pricing holds significant promise for achieving efficiency gains in the consumption and eventually production of power It provides the basis for designing more effective load/demand management strategies for responding to situations of chronic as well as short term capacity shortages and managing situations of temporary excesses in supply Dynamic tariffs based upon a utility's actual cost structure can be used to develop an efficient market for power, a market which offers the potential for reducing the total cost of electric service as well as maximize the value of service to all customers [23]

It is appropriate to note that this paper does not advocate the view that tariffs with more real time features are necessarily superior to those with fewer such features The challenge is to determine in each situation the minimum set of real time parameters necessary to enhance economic efficiency just up to the point of diminishing returns For example, the EDF, Swedish, and Ontario Hydro tariffs described in this paper illustrate in our opinion that a substantial portion of the potential for opportunistic gains in short-term efficiency can be captured with dynamic tariff forms that are relatively inexpensive to administer and relatively easy for most customers to comprehend and respond to, and without having to resort to the more extreme real time forms of pricing such as half-hourly, hourly, or even a daily update in the tariff The latter forms of dynamic pricing, at least in the near to mid-term, may be better suited for some of the very large electricity users with sophisticated response capabilities and a substantial potential for achieving bill savings

Among some commonly heard first-time reactions to dynamic tariffs are they are relevant primarily for thermal systems and not for hydro-dominant systems, since the former exhibit substantial variation in their short-run cost structure whereas the latter do not, that such tariffs are overly complicated to understand and therefore to respond to, that most customers do not have the flexibility to adjust their time-of-use pattern of electricity consumption, and that they are too expensive to administer (communication, metering, billing etc.)

Addressing the first point, hydro dominant systems are also prone to substantial variations in their short-run cost structure However, in this context the short-run is perhaps more appropriately defined by a period that may span one or more months.

Concerns regarding the ability of consumers to understand and react to such signals are largely dispelled by the French, Swedish, U K, and limited U S experience to date Similar concerns were voiced by some when TOU prices were first introduced nearly two decades ago This is not to deny that customer response may be slow at first With time, users will find more innovative ways to respond and take better advantage of the tariff [8]

Many users prefer and find it easier to respond to dynamic tariffs Whereas prices under such tariffs are prone to more fluctuation, high prices tend to prevail only for short duration [9] In contrast, under a 2-part TOU tariff, for example, the peak period is typically broadly defined -- eight to ten hours per day -- because it must be identified well in advance Many users find it more difficult to manage demand over such longer and continuous time intervals Load deferral or load modification without adversely impacting plant operations is generally easier with shorter duration peak periods

The hardware and software required for any communication, metering, and control required to support implementation the simpler forms of dynamic pricing -- e g, EDF's peak day withdrawal option, Sweden's dynamic interruptible pricing tariffs -- are well tested and have been operational for years In the case of the more sophisticated forms of dynamic pricing -- e g , half-hourly updates of prices signaled every thirty minutes by a computer-to-computer linkage -- recent and emerging developments in microelectronics related to metering, communication, and control [11], [16] are expected to increase the reliability of such equipment and reduce costs Indeed these developments should make dynamic pricing technologically feasible and increasingly cost effective in applications involving smaller users of electricity as well as large users

Another concern sometimes voiced about dynamic pricing is that consumers need stable price signals if they are to make optimal investment decisions about their energy using capital stock which has a long life In this context it should be noted that dynamic tariffs based upon the utility's short run cost structure are not necessarily intended to be a replacement for classical TOU or other pre-determined tariffs that are currently in-place Rather, such dynamic tariffs should be offered as choices/options that are targeted to select customer segments Even in these instances it is unlikely that a certain customer will contract his entire load on a classical static tariff or solely on a dynamic tariff

The decision facing such users is somewhat akin to businesses that buy certain commodities, (e g., oil) and must decide based upon their risk preferences and planning expectations, the amounts of such commodities that are purchased to "lock-in" a stable price under a long-term contract, and the amounts to be bought on the spot market An industrial user might elect to place sixty percent of his load on a conventional static tariff and the remaining forty percent on one or more dynamic tariffs For other users such percentage splits may be 90-10, 10-90, etc.

By offering one or more dynamic tariffs as options, the risk associated with significant short-term efficiency losses is better managed Without such tariffs, this risk must be uniformly borne by all users. However, with such tariffs, a substantial part of this risk is transferred to customers who voluntarily commit a portion of the load to the dynamic tariff Thus, there is a better matching of individual customer's risk preferences and expectations and the amount of risk they shoulder In this process every one benefits,

even those customers who do not select a dynamic tariff

A pertinent and final observation relates to the fundamental linkage between dynamic pricing and short-run marginal costs in competitive markets Economic theory suggests that prices in competitive markets are aligned closer to marginal costs and tend to fluctuate as market conditions range between "tight" and "slack" Indeed, evidence of dynamic pricing is evident in some markets in the U S that have been substantially deregulated in recent years, such as telephones, natural gas, and airlines

For example, with the partial decontrol of natural gas prices at the wellhead and the more recent push by FERC to encourage pipeline companies to become common carriers, the volume of spot gas sales has increased considerably in the bulk sales market Even at the retail level, gas distribution companies and their larger customers are showing increasing interest in interruptible sales contracts

In the airline industry, deregulation and the increased competition is largely responsible for stimulating service unbundling by dynamic pricing, i e, no frills fares, 2-week advance purchase fares, 1 week advance purchase fares, and special fares such as "super-savers", and maxsavers"

A good example of dynamic pricing in this industry is Eastern Airlines Weekender Club Members in this club receive weekly bulletins listing several travel bargains Examples of some recent offerings include the following packages which consist of round trip coach airfare and deluxe hotel accommodations: 4 nights in Buenos Aires (from Washington, D C) for $500, 2 nights in Montego Bay, Jamaica for $229, 2 nights in Nassau, Bahamas for $149, and 3 nights in Los Angeles for $219 These low prices reflect short-run marginal cost pricing and are based upon Eastern's ability to scan its computerized reservation database and identify flights that are judged to be underbooked 2-weeks prior to departure Eastern's hotel partner's conduct a similar computer scan of their room occupancy rates at various locations The matching of substantially underbooked flights and low occupancy hotel locations in real time, is utilized to develop the travel bargains for next week. Initial response to this program is reported to be very positive

As electric utilities confront increasingly competitive power markets in the future, they will also recognize that financial survival under such conditions will require among other responses, the [illegible] dynamic pricing options

FOOTNOTES

1 The term "real time" is used somewhat broadly throughout this paper to indicate signaling of relevant information that is generally done very close to the time of applicability rather than the year(s) time frame for static tariffs.

2 This is in addition to the classical TOU tariffs and the standard interruptible tariffs

3 For example, at present Ontario Hydro forecasts the availability of intermittent power in 1988 is expected to increase to 2,000 hours or more and that the rate will be around 1 0c/kWh

4 All Ontario Hydro tariffs quoted in this paper are in Canadian dollars

5 Real time pricing also provides a means for optimally integrating powe generated by private producers and cogenerators For example, PG&E has recently entered into a novel pricing arrangement for purchase of power from IBM's 65-MW gas fired cogeneration plant in San Jose Energy provided by this plant is purchased on a "post facto" pricing on hourly basis to reflect actual experienced marginal costs PG&E provides a non-binding forecast of prices [6] In contrast, under Niagar Mohawk Power Company's proposed plan for spot pricing of buyback energy from cogenerators, we understand that the company will provid binding forecasts of the hourly price of energy.

6 Detroit Edison also has about 100 MW of wholesale-for-resale load where on-peak rates are based upon actual marginal costs plus a premium

7 Pre-cooling uses the thermal mass of the building as opposed to specifically designed thermal storage options such as chilled water storage

8 Some econometric studies of customer response to the classical TOU tariffs report that the response increases over time, that the response is greater in later years than in the early years, e g, see [1]

9 Even a classical demand charge tariff can impose a very high cost for a brief interval Consider for example, a customer with a peak demand 1 KW who faces a demand charge of $5/kW/month based upon the highest integrated demand over a 15-minute-interval This customer is essentially paying the equivalent of $20/kWh for the unit of consumptio that determines the peak billing demand.

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COMPARISON OF ELECTRICITY PRICING POLICIES IN DEVELOPING COUNTRIES

Dr. Bhaskar Natarajan, Ms. Gopika Bhagat, Dr. S. Ramesh

Background

Tariffs in most developing countries as well as in India have, in the past, been based on an average cost approach. The aim was recover the costs incurred in supplying power to different consumer categories. The tariffs for each consumer category was fixed after giving due weightage to social, economic and financial objectives of the electric utilities. This resulted in a policy of cross-subsidisation amongst different consumer categories. Agricultural and domestic consumers in the rural areas were often given electricity at a rate far less than the average cost to the utility. The loss the utility incurred from these consumers was often only partly made up by a tariff which was at times higher than the average cost of supply for the industrial and business/commercial consumers. In spite of this, most of the utilities incur large losses and have difficulty in generating resources for future projects. The general policy followed in fixing tariffs are:

(a) Small consumers (eg. residential, commercial etc.) are generally charged an average energy rate for energy consumed.

(b) Large consumers (like industries, offices, showrooms etc.) have a maximum demand (MD) charge per KW based on the maximum demand from the comumer. A point to note is that the MD charge is generally not related to the time of incidence of maximum demand. This is in addition to the energy rate levied per unit for energy consumed.

Some utilities have moved from a simple energy rate to having tariffs for different blocks of consumption. Inverted block tariffs are used to discourage higher blocks of consumption implying that consumers have to pay an increasing charge for more consumption. Domestic and commercial consumers in some utilities charge a low rate for the first block (normally less than 50 units) and higher rates for the successive blocks. This also takes care of the social objective of providing electricity at low cost to consumers in the low income categories.

Declining block tariffs, on the other hand, are used to encourage higher consumption to guarantee to the utility a fixed level of consumption. This implies a lower tariff rate for higher levels of consumption. This assists the utilities by giving them increased stability. This is resorted to to encourage consumption in early stages of development in a given area.

Large consumers in some utilities have tariffs that relate to time of consumption. Generally, there exist two energy and/or demand rates, one for designated peak periods and the second for designated off-peak periods. Implementing this tariff structure requires sophisticated metering systems which can record demand and energy during peak and off peak periods.

Some utilities have initiated steps towards rationalisation of existing tariff structures in order that the tariffs are at or near the long run marginal costs for different consumer categories. Over the years, the changes in tariffs have not kept pace with the increases in the cost of basic inputs like coal, oil etc. Overheads, including administration expenses, cost of capital etc. have also risen sharply. The burden arising out of these increases has not been fully met and has not been evenly distributed falling largely on high tension consumers. Low tension consumers in the domestic and particularly the agricultural sector have more often than not been freed almost entirely from price increases. As a result, agricultural and domestic tariffs have fallen in real terms in several utilities.

It is considered useful to study the practices adopted in some developing countries like Thailand, Bangladesh, India, Korea etc. to enable lessons to be learnt for mutual benefit for all concerned. The study is expected to arrive at a methodology for calculating a rational tariff structure that is based on the structure of economic costs incurred in generating categories at different localities all over the licensed area.

Identification of Countries

The main objective of the study is to enable lessons to be learned from the experiences in electricity pricing policies in some developing and developed countries for mutual benefit of these countries. The study is expected to provide guidelines to India for enabling rational tariff policy formulation in the future. Keeping this objective in view, it is proposed that the electricity pricing policies of four countries in Asia, viz., Korea, Thailand, Bangladesh and India be studied.

The rationale for selecting the above four countries is as follows:

Korea has the most sophisticated tariff structure, incorporating long run marginal costs as well as time-of-day and seasonal rates. Korea is essential for the study because it has introduced time-of-day tariffs systematically and its experience in formulating and implementing time-of-day tariffs could yield valuable lessons for utilities in India and in other developing countries. Bangladesh, has recently introduced time-of-day rates and seasonal rates which need to be studied. Thailand has some innovations in its tariff structure. In addition, representative load curves for different consumer categories have been drawn by the Provincial Electricity Authority. This is an area in which little has been done in most developing countries; it is felt that the research pay-off from the study of these systems will be considerable.

Electricity Tariffs in Thailand

Thailand, has three electric utilities: the Electricity Generating Authority of Thailand (EGAT), the Metropolitan Electricity Authority (MEA) and the Provincial Electricity Authority (PEA). The responsibility of EGAT is to generate and transmit electricity to the MEA and PEA. In addition, the EGAT has also interconnected its transmission system to neighbouring countries, Laos and Malaysia.

The MEA is in charge of providing electricity to serve 6 million people in the Bangkok Metropolis. The Provincial Electricity Authority (PEA) is a state enterprise under the control of the Ministry of Interior and was established in 1960. The PEA is responsible for providing electricity to 70 provinces throughout the country.

In the fiscal year 1986, EGAT had a peak demand of 4181 MW. This was met by an installed capacity of 2096 MW of hydro, 4444 MW of thermal and 265 MW of gas turbines. An analysis of the composition of consumer categories, energy sales and revenue from different consumer categories reveals the following (see Table 1):

(a) Even though the number of residential consumers account for almost 99 per cent in PEA and 82.5 per cent in MEA, in terms of energy sales, their share is 34.6 and 21 per cent respectively and they contribute to 30 and 20 per cent of total revenues.

Table 1: Breakup of electricity consumption in 1986

Consumer category	MEA (%)	PEA (%)
Residential	21.02	34.60
Small Business	13.57	7.70
Large Business	20.32	8.23
Small Industrial	13.83	14.17
Large Industrial	28.92	30.58
Special Rate		
Large Industrial off-on Peak		
Public Street Lighting, Hospitals	0.60	0.37
Agricultural Pumping		0.53
Temporary		0.33
Free Supply		0.56

(b) The industries and business categories (large and small) account for over 60 per cent of total energy sold in both PEA and MEA. The revenue contribution from these categories works out to 65 and 75 per cent for PEA and MEA respectively.

(c) The revenue realized from different categories varies from 1.16 - 2.19 baht/kW for PEA and from 1.39 - 2.14 baht/kw for MEA. As expected, the revenue realised per unit is lowest for street lighting and highest from the business categories.

The Provincial Electricity Authority has attempted to study the hourly load patterns of important consumer categories like residential, small business, large business, small industrial and large industrial consumers. The load cycle for categories studied is given in Figure 1. The residential load cycle peaks in the morning around 6 a.m. as against the expected evening peak found in most developing countries. Small business has a day-time peak, whereas large business has an evening peak around 8-9 p.m. Small industries have the expected day-time peak and large industries have a rather uniform load cycle, except for a small rise in the morning around 11 a.m.

The energy and demand rates for different consumer categories is given in Table 2. The highlights of the tariff structure are:

(a) An exceedingly large number of blocks in the residential (10 blocks) and small business (6 blocks) energy tariffs;

Table 2: Tariff Structure in PEA and MEA, Thailand Rates, effective June 1, 1987

Consumer category	Energy rate Baht/kWh	Demand Charge Baht/kW	Average Revenue Baht/kW
Residential	0.7 - 2.43		1.3919
Small Business	1.77 - 2.50		2.0978
Large Business (< 11KV)	1.28 -	239	2.0992
(> 11KV)	1.23	229	
Specific (< 11KV)	1.28	233	1.7425
Business (> 11KV)	1.23	216	
Small Manufacturing & Mining (discount 4 %)	1.23	177	1.7494
Medium Manufacturing & Mining (discount 4%)	1.23	174	1.6032
Large Manufacturing & Mining (discount 4%)	1.22	170	1.4905
Electrolysis (discount 4%)	1.20	165	1.4022
Water Works (< 30KW)	1.82		1.6512
(> 30KW)	1.23	167	
Government Office	1.82		1.8275
Non Profit Organization	1.84		1.8692
Agricultural Pumping	1.17		1.2057

Note:
(1) Minimum charge for 3-9 calculated 30% of highest demand charge of the last 12 months)
(2) Demand charge relates to maximum demand in the billing period and not related to time of maximum demand.

(b) The demand charge is levied for all categories except residential, small business, water works (less tha 30 KW), agricultural pumping and government offices;

(c) The maximum demand charge relates to the maximum demand achieved in the billing period and is not

related to the time-of-incidence of maximum demand from the consumer;

(d) All industrial consumers have a flat discount of 4 per cent in their demand and energy rates;

(e) There is a fuel adjustment clause to take care of increase in fuel prices.

The minimum MD charge for various consumer categories is calculated as 30 per cent of the highest MD over the last 12 billing periods. Also, the MD of all consumers is monitored and if found in excess of 30 kW, will automatically be reclassified under the appropriate category. If at any time, the MD of this consumer falls below 30 kW, the consumer will be brought back into his original category. All consumers have a power factor penalty when the power factor falls below 0.85.

It is interesting to note that PEA and MEA had a peak and off-peak demand charge for large industries in 1983 and a declining block tariff for small and large industries. In the tariffs which came into force from June 1, 1987, the time differentiated rates as well as the declining block tariffs have been given up. We propose to look into the reasons for this shift. Also, in the latest tariffs, energy rates for almost all categories have been brought down while increasing the demand changes for all categories. However, the index of electric rate with 1976 as the base has remained steady around 300-302 for the period 1982-86. We propose to analyze these changes in detail in the final report.

Electricity Tariffs in Bangladesh

Bangladesh Power Development Board (BPDB) was formed in 1972 and has over all responsibilities for the generation, transmission and distribution of electricity in Bangladesh. Due to the Brahmaputra-Jamuna river, Bangladesh electricity system has developed in two separate parts, in the east and west zones and the two zones are interconnected. BPDB had a peak demand of 1083 MW in the fiscal year 1987 and this was met with an installed capacity of 1797 MW comprising of 130 MW of hydro and 1148 MW of thermal and 519 MW of diesel and gas capacity. In BPDB as in other utilities, the industrial category accounts for over 50 per cent of the energy sold (see Table 3).

Table 3: Break-up of number of consumers and energy sold for BPDB (1985-86)

Consumer Category	% No. of Consumers	% Energy Sold
Domestic	65.93	22.90
Small Industrial	4.80	9.61
Small Commercial	27.54	8.41
Large Industrial & Commercial	0.20	42.51
Agriculture	1.32	1.55
Others	0.21	15.02

Details for tariff structure for (BPDB) are given in Table 4. Bangladesh has been one of those among the developing countries to have introduced innovative features in electricity tariffs. The most important among these features are the time-of-day tariffs and seasonality in tariffs. BPDB has resorted to recovering the fixed cost through a service charge for each category. Also the power factor that has to be maintained is set at .95 and a power factor correction charge is levied from consumers whose power factor falls below 0.95. BPDB expects all consumers to maintain unity power factor as nearly as practicable.

BPDB could be one of the few countries who levy a demand rate from residential, agricultural, small industries, non-residential light and power (hospitals, educational institutions and all classes of consumers other than those specified under category A, B, C, E & J, having sanction load upto 50 KW). The demand charge for these consumers is levied on the sanctioned load that the consumer has from the Board. It is the responsibility of the consumer to inform the board of additions to connected load which is likely to place additional burden on the Board.

The time-of-day tariffs applies to all categories except residential, non-residential light and power and street lights and water pumping for drinking purposes. The peak hours have been defined from 1700 hours to 2300 hours and the off-peak hours are defined from 2300 hours to 1700 hours the following day. It is important to note that there is no time differentiated demand charge and differences in rates existing only in energy tariffs. The ratio of peak and off-peak energy rate varies from 2.5 to 3.5 across categories. The variation is largest for extra-high voltage general purpose category where the peak and off-peak rates are Tk 2.75 and Tk 0.75 respectively.

Table 4: Details of tariffs for BPDB

Sl.no	Consumer category	Energy rate Tk/kWh	Demand rate Tk/kW	Remarks
A	Residential	1.25	10	< 70 kWh
		1.40		71-200 kWh
		2.85		> 200 kWh
B	Agricultural Pumping			
	1. Irrigation season			
	(a)	1.70	35	Before TOD meter installed
	(b)	1.35	35	TOD tariff off-peak
		4.00		TOD tariff peak rate
	2. Off-irrigation season			
		50		Minimum charge for 1-phase/month
		200		Minimum charge for 3-phase/month
C	Small industrial			
	(a)	2.30	35	Before TOD meter installed
	(b)	2.00	35	TOD tariff off-peak
		4.25		TOD tariff peak rate
D	Non residential hospitals, educational institutions etc.	1.65	15	
E	Commercial			
	(a)	2.80	20(1)	Before TOD meter installed
	(b)	2.00	40(2)	TOD tariff off-peak
		5.40		TOD tariff peak rate (1) for supply at 230/430 volts (2) for supply at 6350/11000 vo
F	Medium voltage general purpose			
	(a)	2.10	40	Before TOD meter installed
	(b)	1.70	40	TOD tariff off-peak
		4.00		TOD tariff peak rate
G	EHV general purpose	0.75	35	off peak rate
		2.75		peak rate
H	HV general purpose			
	(a)	2.00	35	Before TOD meter installed
	(b)	1.65	35	TOD tariff off-peak
		3.75		TOD tariff peak rate
I	HV bulk supply			
	(a)	1.14	N.A	Before TOD meter installed
	(b)	0.80		TOD tariff off-peak
		2.90		TOD tariff peak rate
J	Street lights water pumping	2.15	35	

Note: (a) Demand charge for Residential is based on sanctioned load (except for consumption < 70 kWh)
(b) Demand rate for agricultural and small industrial based on sanctioned load > 20 kW

BPDB also has a seasonal component for agricultural tariffs. During the off-irrigation season, if the consumer wishes to retain the electricity connection, bills will be made on the basis of the actual energy consumed or at the rate of the following seasonal minimum monthly charges which ever is higher. The demand and service charge will not be applicable during off-irrigation season in agricultural consumers.

As in other utilities, BPDB has a fuel adjustment clause to account for increase in fuel prices where energy has to be assessed. BPDB uses specific energy consumption factor, which is calculated on the basis of production and energy consumed during the last 12 months.

We propose to collect data pertaining to impact of time-of-day tariffs on BPDB's load curve. Also, data relating to calculation of tariffs and methodology adopted for implementing TOD tariffs would be studied.

Peak Load Pricing in Korea

Korea's experience in introducing a peak load pricing structure would be of immense use for developing countries. The savings reported after introduction of time differentiated tariffs have conclusively proved the usefulness of these tariffs for load management. The Korean experiment highlighted the fact that apart from calculation of peak and off-peak tariffs, equally important is the preparation prior to implementing these tariffs.

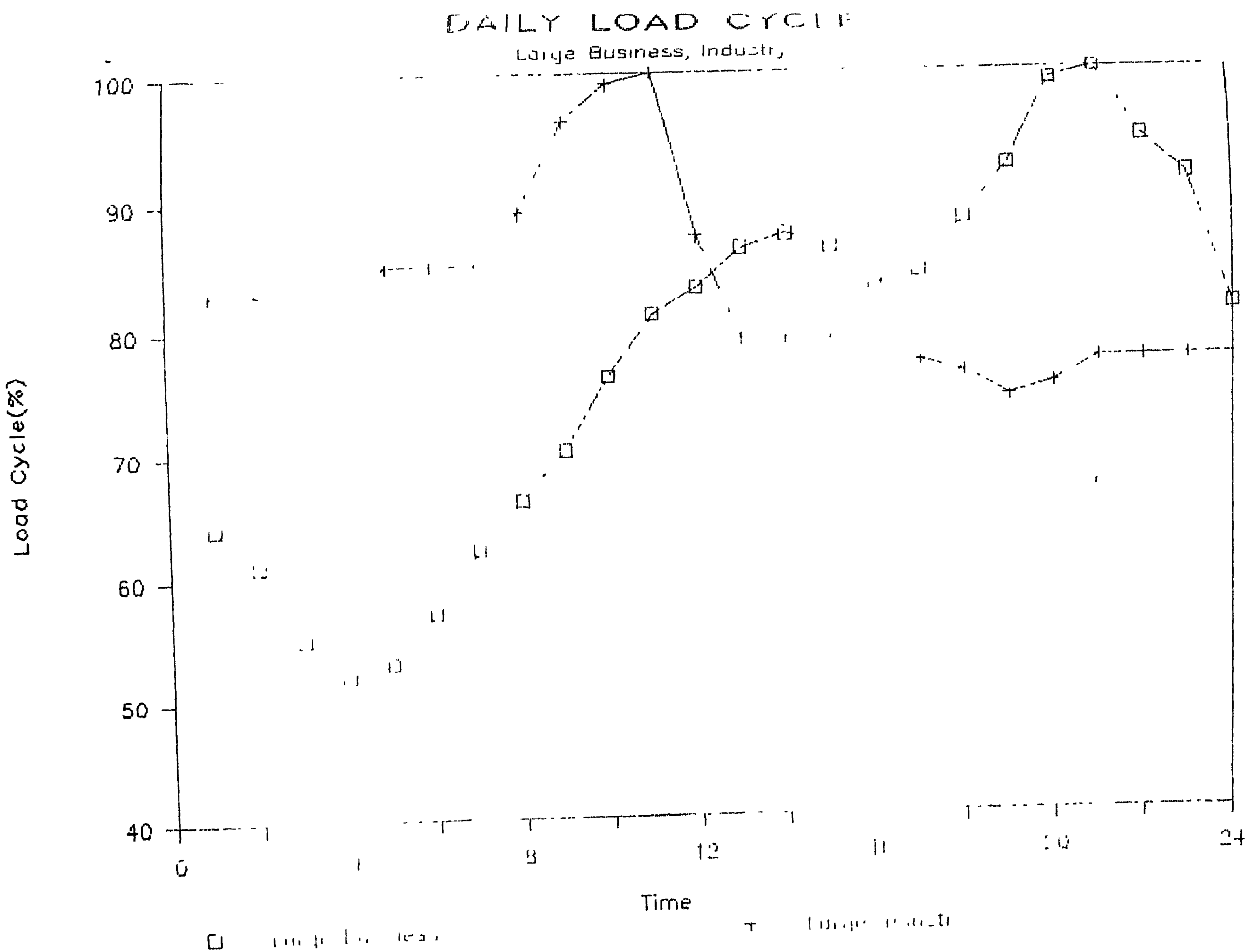
The Korea Electric Power Corporation (KEPCO) divided the tasks into:

(a) Calculation of marginal costs;
(b) Forecasting loads; and
(c) Estimating the impact on the system loads.

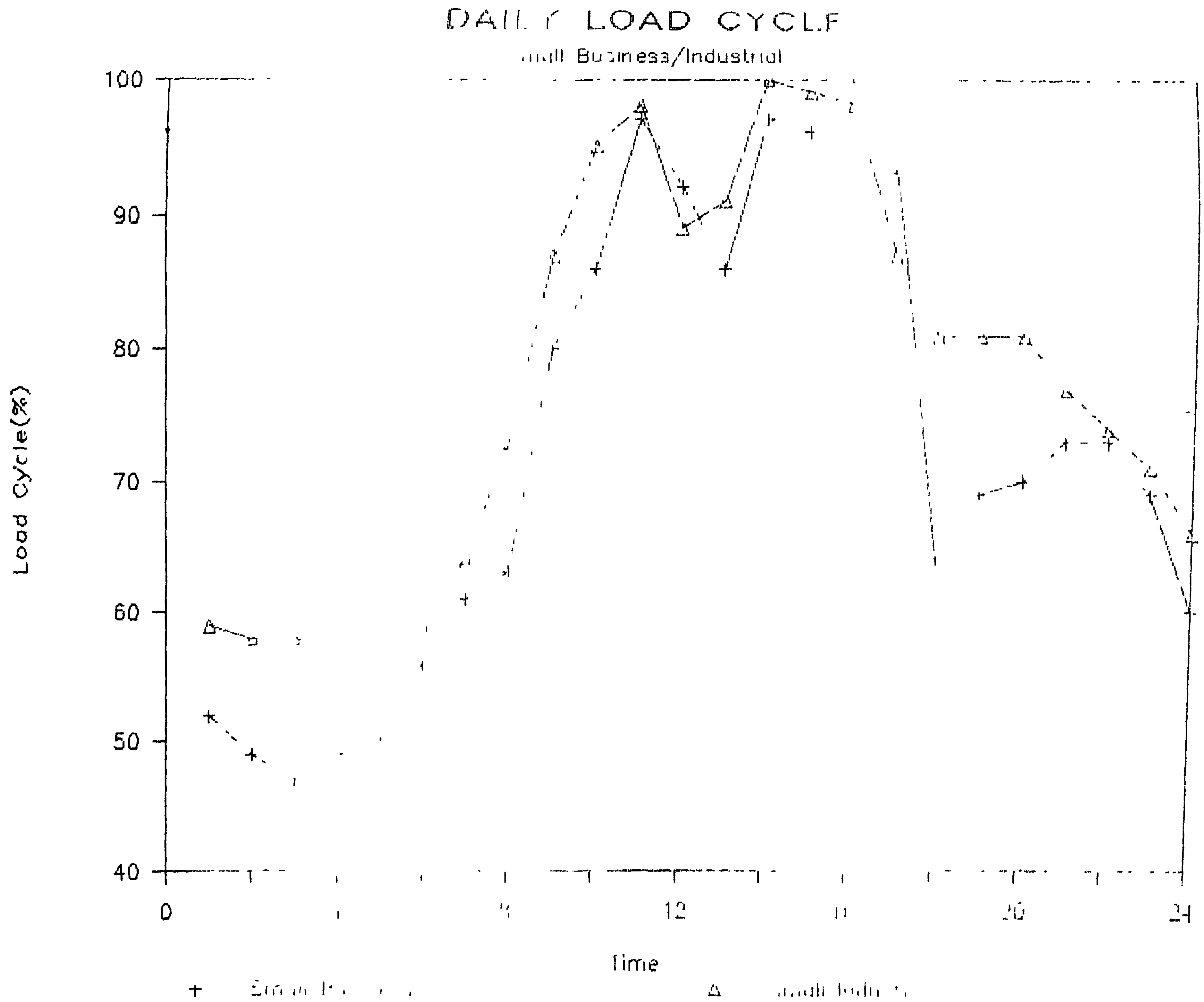
These tasks were completed in the period of 12 months. The peak period was defined as from 1700-2200 hours, intermediate period from 0600-1700 hours and off-peak period from 2200-0600 hours. The estimation of impact on the system load was carried out by analyzing energy consumption patterns of consumers. A survey was carried out amongst 1306 consumers to determine possible shifts in loads from peak to off-peak hours. The survey was carried out independantly by KEPCO and the Korean Chamber of Commerce and Industry (KCCI). The estimates showed a possible reduction in peak loads by 16-20 per cent. The preparation period prior to introducing peak tariffs was 18 months. Peak load pricing was enforced

on November 1, 1987. The impact on the peak loads were immediately felt and the peak ratio (ratio of peak to average load) came down from 127.3 to 119.7 and the off-peak ratio increased from 79.5 to 85.7.

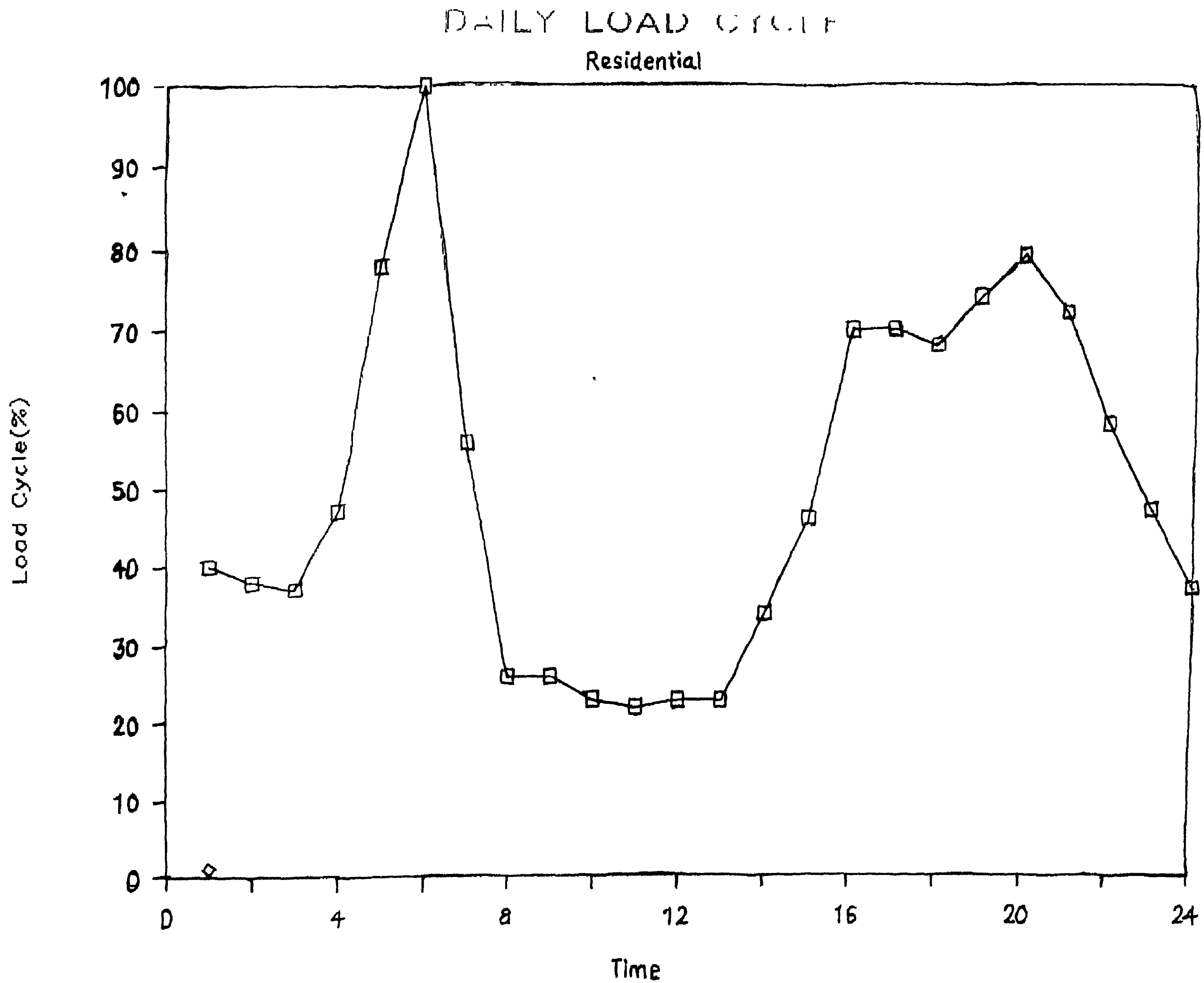
We propose to study the entire experiment in detail for drawing up of lessons to be learnt for developing countries.



DAILY LOAD CYCLE
Large Business, Industry
Load Cycle(%)
100
90
80
70
60
50
40
0
8
12
24
Time



Small Business/Industrial
Load Cycle(%)
Time


DAILY LOAD CYCLE
Residential
Load Cycle(%)
100
90
80
70
60
50
40
30
20
10
0
0
4
8
12
16
20
24
Time

POWER UTILITIES AND END-USE ELECTRICAL ENERGY CONSERVATION IN DEVELOPING COUNTRIES

Reading Material for Training Programme
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POWER UTILITIES AND END-USE ELECTRICAL ENERGY CONSERVATION IN DEVELOPING COUNTRIES

by

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1. Introduction

The installed power generating capacity equalled nearly 300 GW in developing countries as of 1980 (World Bank, 1983). The total electricity production in the same year was about 1320 billion kWh, which represented about 20 per cent of the world electricity generation. According to a World Bank estimate, during 1980–95, electricity production in developing countries as a whole would increase at an average rate of 8.7 per cent/year. This means that at the end of the 15-year period, electricity production in the developing countries would have increased by a factor of three. Despite this level of growth, much of the population in less developed countries would still not have access to electric power in the households.

In India, the electric power generation capacity at the end of March 1987 was 54087 MW. The total power generation increased from 4.1 billion kWh in 1947 to about 188 billion kWh in 1986-87. The electricity consumption grew at 8 per cent compounded during the period 1970-71 to 1986-87, i.e., from 43.724 billion kWh to 146.332 billion kWh in 1986-87. While large investments (about 35 per cent of the total Seventh Plan allocation) are being made in the power sector to increase the capacity, the gap between supply and demand at present is slightly over 10 per cent. So far very little attention has been given to energy conservation as a means of reducing this gap.

Table 1. shows total electricity consumption per capita and the sectoral breakdown in the ten most populated developing countries. The total population in these ten countries was 2.4 billion in 1982. The per capita consumption ranges 40-fold between that of Bangladesh (26 kWh/capita/a) and that of Brazil (1038 kWh/capita/a). For comparison, electricity consumption in the 21 industrialized nations of the International Energy Agency averaged 6400 kWh/capita in 1983 (IEA, 1985).

In nine of the ten countries listed in the table, the industrial consumption was more than one-third of the total electricity consumption. The commercial and agricultural consumption ranges from 10–40 per cent of the national totals. The fraction consumed by the residential sector varies substantially between

Table 1 – Electricity Consumption in the Ten Most Heavily Populated Developing Countries in 1982[a]

Country	Total Electricity Consumption (kWh/cap/yr)	Residential Sector Share (%)	Comm. & Agri. Sector Share (%)	Industrial Sector Share (%)	Other (%)
Bangladesh	26	18.3	14.3	67.4	--
Brazil	1038	20.6	24.3	55.1	--
China (PRC)	279	7.1	17.5	74.8	0.6
India	136	12.5	24.9	55.8	6.9
Indonesia	60	45.9	19.0	31.3	3.8
Mexico	841	20.4	10.5	54.5	14.7
Nigeria	56	46.0	19.0	35.0	--
Pakistan	133	27.6	26.6	36.9	8.9
Philippines	316	20.0	39.4	40.6	--
Thailand	317	21.7	14.9	62.6	0.8

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a Total consumption includes utility sales as well as electricity generated by self-producers. The sectoral percentages are based on utility sales only.

b Sectoral shares apply to 1978.

Source : World Bank, 1985.

nations, from a low of 7 per cent in China to a high of 46 per cent in Indonesia and Nigeria.

Motors, largely in the industrial sector, are estimated to account for about 50 per cent of total electricity use in many developing countries. In the commercial sector, lighting and motors (including those of air conditioning systems) are the primary end uses. Lighting, water heating and refrigerators are the major residential end uses.

In most of the developing countries, including India, there has been increasing awareness of importance of electricity conservation in the recent years. However, this has not been translated into an effective programme of conservation. In some of the developed countries, especially in the U.S.A., the power utilities have taken a keen interest in conservation at the end-use facilities through a comprehensive set of programmes. Moreover, these power utilities have included electricity conservation as an important component in planning future growth strategies. In this paper, a discussion is given on how power utilities in the developing countries could develop programmes for promoting end-use electricity conservation. The importance of electrical energy conservation and its inclusion in power sector planning and the technical and economic potential of conservation are also presented.

2. Why Electricity Conservation

Per capita electricity consumption in developing countries is much lower than that in developed countries; in some cases the order of magnitude difference is over 100. It is considered that increasing the extent and magnitude of electricity consumption in developing countries can be a potent force for better standard of living. However, this does not mean that there should be large wastage of electricity, mainly resulting from inefficiency at various stages from supply to end uses. As electricity is a scarce and costly resource, conservation should play a major role in the developing countries. Some of the more important reasons for the need for electricity conservation is discussed briefly below:

(i) Rapid expansion of electricity supply facilities is costly and difficult. In addition to large investments generated internally, a large portion (about one-third on the average) of capital requirement must come in as foreign exchange.

(ii) Increasing end-use efficiency is much less costly than increasing energy supply. This is clearly illustrated in Table 2 for the industrial sector in India, where coal and oil are also included for the sake of completion. The investment required for creating equivalent energy capacity is Rs. 57.8 billion, i.e., 160 per cent of investment required for implementing energy conservation measures.

Table 2

Industrial Sector in India

Energy Conservation Potential, 1983

Energy Form	Annual Consumption (million tonnes)	Savings Potential (million tonnes)	Investment Required for Creating Equivalent Resource (Rs. million/unit)	Total Investment Required (Rs. million)
Coal	70	17.5	500	8,750
Oil (as fuel)	4	1.0	1,800	1,800
Electricity	60 billion kwh	5250 MW	9	47,250
Total investment for creating equivalent energy capacity				57,800
Investment required for implementing energy conservation measures				36,000
Annual expenditure saving in industrial sector by implementing conservation measures				19,250

Source : Inter-Ministerial Working Group, Summary Report on Utilization and Conservation of Energy, September 1983

The overall annual energy savings is at a rate of 50 per cent, whereas energy generation projects have a much smaller rate of return, resulting in payback periods running into decades.

(iii) There is large potential for increasing the efficiency of electricity use in a cost-effective manner. Studies done in India and Brazil point out that many technological options are available for increasing the efficiency of electricity use. Import of state-of-the art technologies, and / or indigenous production of energy-efficient equipment/devices can be pursued.

(iv) Adopting more efficient end-use equipment will hold down electricity bills when tariffs are rising.

(v) End-use efficiency can help utilities to satisfy social objectives better. More end-use efficiency means that utilities have to invest less in augmenting power generation capacity. The money saved in this process can be invested in bettter transmission and distribution facilities and wider networks. Less power generation also translates to less atmospheric pollution and environmental impact from power plants.

(vi) Increasing the efficiency of end-use equipment can lead to reduction in product cost, and hence, increased sales and export potential.

An indirect benefit from increased end-use efficiency alongwith higher efficiency in power generation, transmission and distribution would result in better grid stability with respect to supply voltage and frequency. This would in turn decrease the specific energy consumption of various products.

3. Potential for Efficiency Improvements

In this section, a brief outline of technical potential for efficiency improvements in the developing countries is presented.

A. Industrial Sector

Some energy conservation studies in developing countries include estimates of overall electricity savings potential in the industrial sector. These estimates point out areas like housekeeping, process improvements and equipment replacement which could bring savings in electricity consumption. The maximum saving is usually achieved in major energy-consuming industries like iron & steel. chemicals, textiles, aluminium, pulp and paper and engineering industries. Most of the savings potential is highly cost effective, and if implemented along with similar oil,gas and coal conservation measures, electricity conservation measures could accelerate economic growth in developing countries.

(i) Motors

Most of the electricity consumed by industries is used to power motors (e.g., in India, the electrical motor power consumption in industry is 60-70 per cent of the total electricity consumed by industry). It is possible to obtain direct electricity savings through the use of motor speed controls that better match motor output and load. Increasing power factor is another important energy and cost-saving measure.

Motor Speed Controls. For many motor applications, there are substantial energy losses during part-load operation. When the load on motor-driven pumps, compressors, blowers, etc. is below the rated value, the motor drive is normally operated at constant speed and a throttle valve or damper is used to reduce the flow rate. There are large pressure and power losses across the throttle or damper.

Various technologies for motor speed control and energy conservation during part-load operation are available, including eddy current couplings, hydraulic couplings, DC motors with rectifier or thyristor controls, AC slip ring motors, and electronic variable frequency drives (VFDs). VFDs employing silicon-controlled rectifiers and thyristors are the most efficient means of controlling motor speed over a wide range of loads.

Power Factor Controls. Maintaining a power factor of 0.95 or greater will reduce distribution losses, lower maximum power demand, and increase motor efficiency. An adequate power factor can be obtained by using motors with a high power factor or by adding capacitors for power factor correction.

(ii) Industrial Processes

After motor drives, electrolytic processing is the next largest industrial end use in industrialized nations. Electrolytic processes such as aluminium and chlorine production are also important in many of the developing countries. Process heating is the other major category of industrial electricity use.

Aluminium. For the aluminium industry, improved smelters consume about 13 kWh/kg of hot aluminium, about half the level typical of smelters installed 40 years ago.

Chemicals. Chlor-alkali industry accounts for about 4 per cent of industrial electricity consumption in India (NPC, 1983). Improved diaphragm and membrane cells consume at least 25 per cent less power.

Steel. Electric arc furnaces (minimills) typically consume 0.55-0.75 kWh/kg of liquid steel, 4-6 times the electricity intensity of coke-fired processes. Use of scrap steel rather than iron ore

lowers electricity consumption by about 25 per cent. Other opportunities for reducing power consumption include preheating of scrap, use of oxygen lancing to assist melting, use of improved electrodes, and ultra-high power furnaces. The latter can reduce electricity consumption to 0.45-0.5 kWh/kg of steel.

B. Commercial and Agricultural Sectors

In a number of developing countries (e.g., India and Indonesia) electricity demand is growing most rapidly in the commercial and agricultural sectors. Lighting, air conditioning and motive power are the major end-users of electricity in commercial facilities in developing countries. In the agricultural sector water pumps are the major consumers of electricity.

Improved lighting fixtures, lamps, lighting control systems and architectural measures would result in electricity saving in the commercial sector. For air conditiners, both architectural measures and mechanical system measures, such as energy-efficient motors, evaporative cooling and variable air volume systems, would result in higher efficiency. For electricity powered pumps in the agricultural sector, use of low-resistance foot valves and pipes, and system with matched components would save energy.

C. Residential Sector

Although the share of electricity consumption in the residential sector is relatively low, there is still a large potential for increasing end-use efficiency through efficient lighting systems, energy-efficient refrigerators and other appliances. Improved insulation material could be used in water heaters and refrigerators. Moreover, higher efficiency compressors in refrigerators and air conditoners can reduce power consumption by about 25 per cent.

4. Power Utilities Role in Electricity Conservation

Most power utilities have traditionally seen themselves as suppliers of a commodity, and like many other enterprises, strive towards increasing profits by increasing sales of their commodity. This has been accomplished historically by constructing new power plants with large capital investments. On the otherhand, conservation programmes which are considerably less expensive than new power generating facilities, and are clearly less risky from an investment perspective, have been more or less neglected **in many developing countries.**

In order to ensure that investment monies are committed to the most cost-effective resource, it is vital both for the national interest and for energy consumers to know whether the deliberate promotion of energy conservation programmes offers a lower cost alternative to investment in new supply. The role of power

utilities in this respect becomes very important.

Examples from Developed Countries

There is growing expertise and experience both in North America and Europe, demonstrating clearly the electrical energy conservation programmes can be introduced in a practical way by utilites, and these would offer a reliable and cost-effective return on capital invested by the sponsoring utility.

In the words of the Tennessee Valley Authority, the largest pubic-owned utility in the U.S.:

> Conservation programmes are treated as a power supply option, since the impact of conservation programmes can be controlled by TVA in the process of planning the power supply system.

The evidence accumulated from 10 years experience of gas and electric utility energy conservation programmes in the USA overwhelmingly supports this statement. The US utilities promote energy conservation investments through grants and loans, which have been demonstrated as successful in stimulating predicted levels of conservation investments. The Pacific Gas and Electric Company of northern California, for example, has offered residential customers free home energy surveys, no-interest loans or cash rebates, and incentives to encourage the purchase of energy-efficient domestic appliances. These schemes have been highly successful not only in encouraging applications, but also in encouraging action from utility's customers. Some 220,000 consumers undertook comprehensive energy-saving work on their homes through the cash rebate scheme in 1985 alone, while the zero-interest loan scheme has attracted more than 440,000 participants.

Commercial and industrial customers have also been encouraged and with similar success. There are other utilities in the USA who have promoted energy conservation. Some of the others are Brooklyn Union Gas, Florida Power and Light, Northern States Power or Potomac Electric Power Company. All these utilities use energy conservation as a fifth fuel.

In Europe, the Oslo Lysverker (the Oslo City Light Company) is a good example of an utility running an energy conservation programme, by which they plan to reduce the gross 1980 consumption by 15 per cent by the year 2000. This savings target was reached by comparing the estimated cost of saving one kilowatt-hour compared to the long-run marginal cost of new supplies. On a conservative basis they estimated that 15 per cent of 1980 production would be an achievable economic target with investments always below the long-run marginal cost of certain new supply options.

Oslo Lysverker promote conservation investments through a system of grants and loans implemented by trained and qualified energy auditors. These grants and loans apply to all classes of

customers—industrial, commercial and residential. The important point is that through the use of various types and levels of incentives, Oslo Lysverker is succeeding in cost effectively acquiring the energy conservation resource that they have planned.

Developing Countries—Implementing End-Use Electricity Conservation

Governments and utilities in many developed countries and in some developing countries have designed programmes and implemented them to encourage end-use electricity conservation. Table 3 lists different options available to the power utilities towards better end-use efficiency. In general, these activities and programmes are intended to overcome the technical, economic and institutional barriers.

The range of implementation-oriented activities mentioned in Table 3 is reviewed in this section.

A. Data Collection

Data on electricity consumption are needed for judging where to concentrate conservation efforts and for estimating the savings that could result. In many developing countries, data on electricity end uses are poor or even nonexistent. However, in some countries like India, every year comprehensive surveys are conducted by central agencies. Field (energy use) surveys and measurements, billing data analysis, and customer reports are needed to determine the amount of electricity consumption and load profile by major end use. This information is most useful when disaggregated by customer type (e.g., type of business or industry).

B. Equipment Development, Demonstration and Testing

In larger developing countries that produce their own motors, air conditioning equipment, lighting products, etc., there is need to develop and bring to marketplace more efficient equipment. Advanced products such as variable frequency motor drives, heat pumps, compact fluorescent lamps, and efficient refrigerators can be produced in countries like Brazil, Mexico, India and South Korea. In all developing countries, it would be useful to demonstrate and monitor the performance of newer energy-efficiency equipment (either domestically produced or imported).

Direct partcipation of utilities in the above cases may not be possible in certain instances. However, utility should show keen interest in these programmes and exercise their influence in matters pertaining to end-use electricity conservation.

Table 3 : Different Types of Conservation Programmes

A. Data Collection

1. Energy use surveys
2. Industrial and commercial reporting

B. Equipment Development, Demonstration and Testing

1. Technology research and development
2. Demonstration and performance testing

C. Information and Education Programmes

1. General information
2. Efficiency labels
3. Energy audits
4. Training
5. Energy conservation centers

D. Incentives

1. Grants
2. Rate incentives & disincentives
3. Rebates
4. Competitions and awards

E. Financing Programmes

1. Utility loans
2. Thirty-party financing through energy service companies

Source : American Council for Energy-Efficient Economy, Washington, D.C.

C. Information and Education Programmes

Utilities along with government agencies and private sector can promote the purchase and use of more efficient equipment through consumer information and education. There are various ways this can occur, including brochures, energy audits, labels and equipment, technical assistance, training and mass media campaigns. To perform tasks associated with information dissemination, energy audits and education programmes, the utitlities would be required to set up energy conservation cells at various locations.

D. Incentive Programmes

Governments and utilities have offered a wide variety of incentive programmes to stimulate more efficient electricity use and energy conservation in general. Financial incentives are often necessary in situations where energy prices do not reflect marginal costs (and in some cases are below average costs). Also, incentives can be effective in overcoming certain institutional barriers. Incentives should be structured in a way that makes them cost-effective for the government or utility offering them (i.e., such that the value of the resulting energy savings is greater than the cost of the incentives). For large conservation projects, it would be worthwhile looking at the social cost-benefits, as it is done with large power generating facilities. A careful evaluation of energy conservation schemes, which takes into consideration all aspects of costs and benefits, would be essential before deciding on award of financial incentives.

E. Financing Programmes

1. Utility Financing Programmes

Utilities can finance energy conservation investments on the part of their customers, since they in general, have access to large amounts of capital and they have a record of customer payments which can be used in assessing credit worthiness. Loans can be provided at either the market interest rate or with an interest subsidy. The objective is to reduce the first-cost barrier to investing in conservation and sometimes to offer a loan repayment plan whereby energy bill savings exceed monthly loan payments.

Utility financing is most feasible and cost-effective when the loan is relatively large. With small loans, administrative cost can be high. Thus, utility financing may be most suitable for major efficiency investments by commercial and industrial customers. However, in some instances, e.g., for household electricity conservation, small loans may be considered if it is economically and administratively viable.

2. Third-Party Financing

Third-party financing involves capital investments by someone other than the industry or building owner. This relatively new approach to conservation is gaining popularity in some industrialized countries. For example, there were more than 100 energy service companies (ESCOs) in the U.S. willing to install and provide financing for energy conservation measures in commercial buildings and industrial facilities as of 1984. In many cases, these companies are willing to lease equipment, operate equipment, or enter into a "shared savings" plan with the owner of the facility.

Governments and power utilities in developing countries can encourage third-party financing and energy service agreements in a number of ways. First, a financing corporation can be established that has access to public capital. Second, tax incentives and accelerated depreciation can be extended to energy-efficient equipment installed under a leasing or joint venture arrangement. Third, public organizations can sponsor demonstrations, offer technical and promotional assistance, and provide loan guarantees.

5. Electricity Conservation and Planning for the Power Sector

Incorporating data on disaggregated end-use demand into the power forecasting process will help utilities avoid costly investments in electricity supply if they are not needed. Without an understanding of electricity end use and the dynamic nature of electricity demand, utility and government officials are left with supply system planning and expansion based on historical trends and "business-as-usual" scenarios. Collecting end-use data is one of the first steps for utilities interested in pursuing demand management and planning.

Some utilities in the U.S. are beginning to forecast demand on the basis of electricity end use and engage in integrated supply-demand planning. A survey completed in 1985 shows that utility commissions in at least eight states require utilities to evaluate both supply-side and demand-side options and develop least-cost resource plans.

Conservation can be meaningfully forecast and its cost can be compared to the cost of new supply capacity. Considerable expertise has been developed concerning the ways in which the fifth fuel resource can be assessed. At the Bonneville Power Administration (BPA) covering the pacific north-west, computer programmes have been developed to assess the effect of certain conservation measures upon different aspects of the known building stock. The next step is to assess the penetration rate, the rate at which savings can be achieved. The data is used in comparison with fuel price forecasts and economic indicators to drive the price response components of the BPA's load forecasting models. They also estimate the amount of conservation which would have occurred without the various incentives and

promotional programmes on offer, which is called the 'freeloader' effect.

Conservation supply curves are used as the basis for comparing conservation with other supply-resource spply curves. An important factor in developing conservation and other supply curves is the question of when the resource will be available: new electric generating plants have a discrete construction period - some longer than others - and will only produce power when completed. Conservation, likewise, takes time to 'build', but unlike a generating plant, it produces resources from the outset to completion, i.e., saturation of the conservation measures. With conservation, the "rate of construction" penetration rate is as important as the total project length.

The U.S. utilities which use conservation as a fifth fuel have experience that demonstrates that the effectiveness of conservation programmes can most certainly be predicted with sufficient accuracy for the purposes of utility planners.

6. Conclusion

Additional electricity supply would come not only from new power supply sources, but also from electricity conservation at the end-use facilities. Investments in energy conservation frequently provides better rates of return than in investments in energy supply. The shorter gestation periods for electricity-saving measures should normally encourage equal if not greater attention than power supply options.

There is currently an imbalance in the investment resources being devoted to energy supply and use. If a nation is to receive maximum benefit from the investment resources it expends, then a greater emphasis needs to be placed on conservation.

There are significant and continuing benefits to be gained from increased conservation investments. In the longer term, increased conservation investment should reduce the demand on public funds for energy supply.

Improved electrical energy efficiency will be critical to prolong the life of energy resources. The governments in developing countries must direct their policies towards ensuring that their energy needs are met at the lowest resource cost to the nation. This requires a thorough assessment of the relative economic advantages of investment in supply and demand.

Energy conservation should be made part of power planning process through various techniques including modeling.

The role of power utilities in end-use electricity conservation has taken root in a few developed countries. In developing countries, perhaps there is a greater need for

utilities to pursue various conservation programmes to increase end-use electrical efficiency. This can be achieved through concerted efforts and comprehensive programmes.

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FINANCIAL VIABILITY

OF

STATE ELECTRICITY BOARDS

BY SHRI L.R. SURI

Although according to the provisions of the Indian Electricity (Supply) Act, it is intended that the State Electricity Boards (SEBs) should function as viable commercial undertakings, in actual practice they have not been able to function as such, and in general almost all the SEBs have been incurring heavy financial losses. During fiscal years 1985-86 & 1986-87, the SEBs have incurred losses of Rs. 1545 crores and Rs. 1580 crores respectively. Due to such heavy losses the SEBs are unable to make timely payments for coal supplies, railway freight, power purchases, power equipment and even for spare parts and essential items required for operation and maintenance. The financial sickness of tne SEBs apart from affecting the healthy functioning of these undertakings also casts a shadow on the future growth of the power industry itself in the country. The commercial losses of the SEBs during the VI Plan were Rs. 4472 crores and it has been estimated that at 1984-85 rates the total losses suffered by them during the VII Plan period would be of the order of Rs. 11,757 crores. While framing the Seventh Five Year Plan for the power sector it has been assumed that the SEBs would be required to mobilise additional resources to the tune of Rs. 7,000 crores, which would imply that the commercial losses of the SEBs during the 7th Plan (i.e. 1985-90_ would not exceed Rs. 4757 crores. However, the losses incurred by the SEBs during the fifst two years of the Plan

itself have amounted to Rs. 3125 crores. It would, therefore, be virtually impossible to contain the financial losses within the contemplated figure of Rs. 4757 crores during the entire VII Plan period, since whatever remedial measures have been sought to be initiated so far to achieve this, have not been effective. Under these circumstances, the only option left with the SEBs would be to make up the revenue losses of the Boards by diversion of plan resources which would seriously affect the implementation of the Seventh Plan works. As it is, Rs. 34,273 crores (Rs. 22,687 crores for SEBs) provided in the Plan are barely adequate for the completion of the on-going schemes and hardly any resources would be available for new starts during VII Plan. This being the state of affairs, it would not be possible to commission the projected plant capacity of 22,245 MW during VII Plan, and it is apprehended that we may fall short of the target by 20-25%, thus repeating the performance of the previous plans. Considering that the present power shortage is of the order of 10,000 MW, the disastrous effect that the shortfall in achieving the VII Plan targets will have on our national economy can be well imagined. It is essential therefore that timely action is taken to ensure that the SEBs are able to come out of their financial crisis and start functioning as viable commercial undertakings. In order to accomplish this, measures have to be adopted that would enable them to function as commercially viable units earning a minimum profit of 3% as provided under Section 59 of the Indian Electricity (Supply) Act of 1948 (as amended in 1978).

FINANCIAL VIABILITY OF STATE ELECTRICITY BOARDS

SYNOPSIS

The financial working of SEBs, greatly affects the budgetary position and financial management of the State Governments. Almost 1/3rd of the States' resources are deployed in power development. SEBs are incurring huge financial losses every year because of unremunerative tariffs mainly for supply to agriculture. The SEBs are supposed to be subsidised by the State Governments for losses suffered on account of rural electrification and unremunerative tariff for agriculture. The States were to mobilise additional resources of Rs. 22,212 crores during the Seventh Plan period and no deficit financing was envisaged for them. However, during the first three years of the Plan, the Additional Resources Mobilisation is expected to be of the order of Rs. 2,000 crores only and deficit financing has been of the order of Rs. 700 crores. Under such circumstances no subsidies or subventions can be expected from the State Governments. The Electricity (Supply) Act provides under such circumstances diversion of capital receipts to shortfalls on revenue account. Such diversion of capital resources will result in huge shortfall in additions to capacity and construction of required transmission and back up distribution lines to support the huge programme of tubewell energisation and rural electrification. Together with the existing shortage of 10,000 MW capacity, the conditions will be chaotic in the 8th Plan. It is strange that this has not so far attracted the attention of our economists and planners and nothing is thought of or done, attributing non-action to likely political repercussions. Inspite of non-payment or only part payment of interest on State Govt.loans, the SEBs are unable to make timely payments for supplies and services which is playing havoc with the financial discipline not only in SEBs but also on public sector undertakings like CIL, NTPC, BHEL and Railways to whom they are unable to make timely payments. It is high time that a thorough review of the financial position of the SEBs is made and viable solutions found for their sound working.

In this context the National Council of Power Utilities (N.C.P.U.) had undertaken an in-depth study to analyse the causes responsible for the financial sickness of the SEBs and identify the various causative factors and their relative contribution to the losses. The results of these studies have been reported in the two articles entitled "State Electricity Boards - Why are they Sick? (Economic Times : 21.4.87)" & "Electricity Pricing (Economic Times : 30.7.87)". The results of these studies revealed that one single factor that has been responsible for causing 80% of the total losses suffered by the SEBs is the unremunerative tariff at which they are being made to sell electricity to certain category of consumers especially to the farm sector and to a certain extent to the small industries sector. Although technical & managerial efficiency of the Boards have also to be improved to bring down the financial losses, since the deficiencies in these areas are responsible for about only 15 to 20% of the losses, improvement in the PLF of Thermal Stations and reduction of T&D losses alone cannot pull them out of the present financial crisis. The crux of the matter essentially lies in allowing the SEBs to function on commercial lines and let them adopt a tariff structure which bears some semblance of relation to the costs of production. Such a step alone would help the SEBs to come out of the red and put them on a sound footing.

The N.C.P.U. studies for evolving a rational tariff structure (vide NCPU article: "Electricity Pricing") as a spin-off yielded some valuable data regarding basic financial

parameters which may be regarded as normative. In the present paper these data have been made use of for making an analysis of the SEBs' finances, and for exploring the measures to be taken to restore their financial health.

PRESENT CAPITAL STRUCTURE OF SEBS AND THE NEED FOR CONVERTING A PART OF GOVERNMENT LOANS TO EQUITY.

The capital structure of SEBs comprises Government loans, loans from financial institutions, Market borrowings and Internal Resources of the Boards. The capital structure of SEBs as it stood in 1984-85 is given in Table I. In 1984-85 the capital structure of SEBs consisted of about 95% loans (64% Government loans, 15% Institutional Loans, 16% market borrowings) and of 5% internal resources of the Boards on the basis of which debt equity ratio works out to about 19:1. This shows that the capital expenditure of SEBs is financed predominantly by borrowings from outside agencies and the internal resources form a relatively very small percentage of the total investment. From commercial angle this indicates a very unsound financial position of the SEBs as they have no financial control over the business and are entirely dependant on outside agencies for their existence. This is one of the main factors that has led to the dilution of the autonomy of the SEBs. As against the present debt equity ratio of 19:1, for healthy functioning of the SEBs the desirable capital structure as per normative standards should be made up of not more than 75 to 80% loan capital and balance 25 to 20% of internal resources. On this basis the debt-equity ratio works out to 4:1/3:1 which incidentally is also the ratio

recommended by some of the international financial organizations for sound financial working of the SEBs. The desirable capital structure worked out on this basis is as given in the following Table (Table-I):

TABLE - I

CAPITAL STRUCTURE OF SEBS

Item		Existing Structure (1984-85) (%)		Desirable Structure (%)	
1.	Government loan	64	95	55/50	80/75
2.	Institutional loan	15		15	
3.	Market borrowing	16		10	
4.	Internal Resources of SEBs	5		20/25	
	Total:	100		100	

It will be seen from the above that for improving the debt equity ratio from the present 19:1 level to the desirable ratio of 4:1/3:1, measures have to be taken for reducing the debt component from 95% to 75-80% and correspondingly enhance the internal resources component from present 5% to 20-25% of the total capital structure. In order to achieve this re-adjustment in the relative proportion of loan capital and the internal resources of the SEBs, one of the important measures that should be taken by the State Governments is to convert a part of their outstanding loans to SEBs into equity capital with effect from a fixed date. This would enable SEBs to reduce their loan interest burden and at the same time help them in augmenting their internal resources. It has been assessed that in order to achieve a

4:1 debt equity ratio, it would be necessary to convert 25% of the State Government loans to equity capital.

It may be mentioned in this connection that Rajadhyaksha Committee on Power (1980) in their Report had observed that for restoring a measure of financial independence to the SEBs, about 50% of the annual investments in power on an average should be ~~the~~ funded by internal resources. This would mean a debt equity ratio of 1:1 which may be considered as ideal for public utility undertakings like the SEBs. With this debt equity ratio, the capital structure would comprise 50% loan (25% from State Governments and 25% market borrowings/ institutional loans) and 50% equity (made up of 25% Government equity & 25% internal resources of the SEBs). Achieving a 1:1 debt equity ratio would, therefore, involve conversion of 50% of outstanding State Government Loans to equity.

Government participation in the Equity capital of a public sector company is quite common. Government of India has floated many companies and Corporations with their equity capital participation. N.T.P.C., N.H.P.C., B.H.E.L., are some of the organisations of this nature. The latest amendment to the Electricity (Supply) Act has already made this provision.

DEBT SERVICING CAPACITY OF SEBS

One of the factors which determines the financial soundness of an undertaking is its debt servicing capability. Since the capital structure of SEBs consists of a predominantly high component of Loan (about 95% at present) and only 5% equity, the interest liability on them is very heavy. For instance, in 1984-85, as much as 22% of the revenue receipts

of the Boards were required for meeting their liability towards payment of interest on Government and Institutional loans and market borrowings even though interest on Government loans was not fully paid. About 85% of revenue receipts were required for meeting the revenue expenditure comprising fuel, power purchase, O&M expenditure, establishment charges etc. After making a provision of 9% towards depreciation, they were left with only 6% of revenue receipts against the interest liability of 22%. This amply demonstrates the poor debt servicing capacity of the SEBs. Under the circumstances instead of making a commercial profit they actually incurred a loss of about 16%.

In order that the SEBs are able to earn a commercial profit & reserve of around 3½% of capital at charge as provided in the I.E. Supply Act (equivalent to about 9% of revenue receipts) after defraying the expenses towards fuel, power purchase, O&M, establishment and at the same time have necessary provision for interest payment and depreciation fund, it would be necessary for the Boards to restrict their revenue expenditure to about 60% of revenue receipts (as against the present level of about 85%) mainly by increasing the revenue receipts by adopting remunerative tariff structure and to a certain extent by reducing the revenue expenditure by improving the efficiency of operation viz. improvement in PLF of Thermal Stations, reduction in auxiliary consumption of T&D losses etc., curtailing staff and reduction in establishment charges.

NEED FOR ENHANCEMENT OF DEPRECIATION RESERVE PROVISION

One of the few sources of internal resource generation for the SEBs is the provision made by them for Depreciation on fixed assets in use. Indian Electricity Act has prescribed plant life for various items of equipment for generation, transmission and distribution of power on the basis of which depreciation is calculated by straight line method. One of the main draw-backs of the straight line method is that it does not provide any margin for obsolescence of plant & equipment, although the rate of obsolescence has become very high in modern times due to fast technological developments. According to the provisions of the I.E. Act, Depreciation works out to 3.6% for Thermal and 2.6% for Hydro Plants for 25 years & 35 years of prescribed plant life respectively. These depreciation rates, are too low and unrealistic and are much lower as compared to the depreciation rates calculated as per the provisions of the Income Tax Act.

For a normal healthy functioning, the SEBs are required to generate internal resources equivalent to at least 20% of capital expenditure during the year in addition to meeting the debt repayment obligations. However, the present rates of depreciation (which is the main source of mobilisation of such resources for the SEBs) are not adequate even for repayment of yearly instalment of debt repayments. It is, therefore, necessary to enhance the rates of depreciation. It would, however, not be desirable to reduce the prescribed life of plant & equipment for this purpose.

It would be more realistic to take into consideration the need for major replacements, renovation and modernisation of the plant & equipment during their life time. It would be quite reasonable to assume that 50% of the original cost of the plant & equipment would be needed, for such work during the life time of the equipment. It is, therefore, suggested that this amount required for the major replacements, renovation & modernisation should be provided for while calculating the rate of depreciation. Accordingly, the depreciation rate may be fixed at 5.4% and 3.9% for Thermal & Hydro plants respectively and similar 50% enhancement should be allowed in depreciation rates for equipment used for transmission, distribution, etc.

RETURN ON CAPITAL

As specified in the Electricity (Supply) Act, the rate of return should contribute a reasonable sum towards the cost of capital works after taking into account the availability of the amounts accrued by way of depreciation and the liability for loan amortisation. The present rate of depreciation is hardly adequate for loan amortization; and a rate of return of 3% will ~~hardly~~ not generate even 15% internal resources for cost of capital works during the year against a desirable figure of 20-30%. It is, therefore, necessary to raise the limit of minimum rate of return to 5% from the existing 3%.

ELECTRICITY DUTY

While making its recommendations in regard to return on investments on power projects, the Venkataraman Committee (1964) suggested that the SEBs should yield a return of 11%

on capital, made up of 6% interest on capital, 1/2% for appropriation to reserves, 3% net profit for financing further power & developmental projects and a notional 1½% on account of Electricity duty. This duty which was initially recommended as 1½% of capital cost by the above Committee is actually being levied by the State Governments at a higher rate - average being 2.6%. Actual levies by the different State Governments vary from Nil to 22.6 P/unit for H.T. supply and even upto 31.36 P/unit for commercial supply. As a percentage of the average rate of sale of energy, the duty varies from nil to 15.3%. It has to be appreciated that electricity duty levied by the States, limits the scope for revision of tariffs by the SEBs as the ultimate burden on the consumers has always to be taken into account in fixing tariffs.

This matter was also studied by the Rajadhyaksha Committee on Power (1980), who suggested that the question of considering these duty receipts as a part of the resources of the SEBs and treating these as equivalent to increase the tariffs should be examined by the 8th Finance Commission. The Finance Commission in its report has since agreed that credit should be given to SEBs for the amounts realised by the State Governments as electricity duty. The Electricity duty receipts should be considered as additional resource available to the SEBs and at best be treated as equity capital of State Governments and not as loan capital. It is also necessary to rationalize the Electricity duty on the basis of a uniform rate say of the order of 10% of the relevant tariff for the

particular category of consumers with no levy for agricultural consumers.

INTEREST ON WORKS UNDER CONSTRUCTION.

In the power utilities, at any point of time, works in progress constitute a sizeable proportion of the total block capital. Although works in progress have not started earning revenue, the SEBs are required to meet the interest liability, and the present practice is to debit it to their Revenue Account. This affects the revenue earning capability of the SEBs contributing to their financial sickness.

According to conventional commercial accounting practice, however, the interest on works in progress is capitalised. Since SEBs are also expected to run as viable commercial undertakings, there is a strong case for them to follow this practice. Even some of the international financial organisations have recommended the capitalisation of interest during construction and this practice is accordingly being followed by NTPC, NHPC, etc. This question of capitalisation of interest on works in progress has also been examined by the Eighth Finance Commission and they have agreed in principle with this view. The SEBs should, therefore, be allowed to capitalise the interest on their various works in progress during the year. This would reduce the interest liability of the Electricity Boards and thus help in mobilisation of additional resources which are so very necessary for improving their financial health.

MOBILISATION OF INTERNAL RESOURCES

As already discussed, the existing capital structure of SEBs presently made up of about 95% loans and 5% internal resources has to undergo a thorough restructurring so as to comprise 75-80% loans and 25-20% internal resources. This means that the internal resources mobilisation has to be augmented from the present level of about 5% to 20-25% which is, no doubt, a formidable task. Basically the internal resources consist of capital contribution from new consumers and provision for depreciation fund and revenue surplus. The tools available for raising the level of internal resources are therefore: (a) raising depreciation provisions; (b) raising the rate of return on capital; and (c) by generating higher surplus i.e. earning of higher revenues. These measures in the short term would mean higher electricity prices to the consumers. However, in the long run this will result in savings in cost, since the additional internal funds that would become available to the SEBs would not involve liability for paying interest and would reduce the component of borrowings which is financially expensive. In this context the proposition of reducing a part of the Government loans to equity capital would also go a long way in augmenting the internal resources of the SEBs.

Summing up, in order to avoid the diversion of capital receipts of the SEBs to meet the shortfalls in their revenue accounts which would have disastrous consequences on the implementation of the Seventh Plan targets, it is essential that remedial measures are taken immediately

to ensure that the SEBs turn the corner in the shortest possible time and start functioning as commercially viable units. The unsound financial position of the SEBs is not only affecting their own performance but is also adversely affecting the finances and performance of the other allied sectors with which the power utilities have close links. It is, therefore, necessary that a critical review of the financial working of the Electricity Boards is undertaken on a priority basis with a view to finding viable solutions for restoring their financial health.

NATIONAL COUNCIL OF POWER UTILITIES

State Electricity Boards - Why are They Sick?

In an unusually frank discussion on the performance of the Public Sector in the country Shri Vasant Sathe, Minister for Energy, has told us some bitter home truths in a recent series of articles in one of the leading Indian Dailies. Coming as it does, from a senior Minister of the Government, this critical self-apraisal of the performance of the public sector, his analysis of the various factors that have contributed to the present condition of this sector and the remedies suggested by him to restore their health should lead to an instrospection on the part of everybody connected with the public sector. It is against this background that the National Council of Power Utilities, a body representing the various power utilities in the country, undertook a self-assessment of the performance of the utilities in the power sector.

The State Electricity Boards are primarily responsible for the generation of electric power, its transmission over long high-voltage transmission net works to far flung areas in the State and finally distributing the power to the consumers over an extensive distribution network. Thus, the State Electricity Boards are entrusted with an enormous responsibility for meeting the aspirations, in as far as power supply is concerned, of all the sectors of the economy as well as the common man. As is well known, the country is currently going through a phase of critical power situation and chronic power shortages and power-cuts have become a part of our day-to-day life.

Who is to be blamed for this state of affairs? It is very tempting to the generally uninformed critic to put the entire blame on the SEBs who are dubbed as suffering from technical and financial incompetence, bad management, corruption and a host of other malaise

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real or imaginary. Is this harsh judgement of the role of SEBs based on facts or on certain popular misconceptions? Let us make a critical analysis of the various factors that go into the functioning of the SEBs before we summarily accuse them for all the ills of the country's current power problems.

The principal parameters that have to be considered for a scientific analysis of the performance of the SEBs fall under two categories - technical and financial as listed below:

Technical

(i) Productivity (Plant Load Factor);
(ii) Losses in Transmission and Distribution Systems;
(iii) Fuel Consumption (Coal & Oil);
(iv) Energy Consumption in generating auxiliaries;
(v) Expenditure incurred in operation and maintenance; and
(vi) Employment and Productivity of Labour.

Financial

(i) Market and Institutional Borrowing;
(ii) Repayment of Loans;
(iii) Payment of interest on Market & Institutional Loans;
(iv) Commercial (Profit/Loss);
(v) Generation of Internal Resources;
(vi) Return on Capital employed; and
(vii) Susidies.

We may now discuss in detail the role of the above factors vis-a-vis the performance of the SEBs, both financial and technical, and try to make an unbiassed evaluation of the impact made by these, individually and collectively, on the performance of the SEBs.

Commercial Losses

The Planning Commission has estimated the losses suffered by

the SEBs in the country in 1985-86 to be of the order of Rs.1438 crores. These are mainly due to the average tariff of the Boards, 55.2 paise, per Kwh, being lower than their average operating cost of 69.53 p per Kwh. Planning ,Commission has attributed Rs.1134 crore loss in revenue due to low tariff for agriculture which averages to 18.47 p/Kwh only. Further Rs.11 crore could be attributed to low tariff for L.T. Industries. Apart from these there are revenue losses due to low tariff for domestic and even H.T. Industries in some of the States.

It, therefore, appears that the main factor responsible for the poor financial health of the SEBs is the unremunerative tariff structure that the Boards have been forced to adopt. There is, however, no doubt that the technical performance of the Boards can be further improved by reduction in the number of employees, increasing the PLF, reducing the T&D and auxiliary losses as well as reducing fuel consumption, etc., upto certain normative levels.

A detailed in-depth discussion on these factors follows in the ensuing paragraphs.

Un-remunerative Tariff Structure

An assessment of the losses suffered by the SEBs, which have a comparatively higher component of agricultural loads, shows that the SEBs are suffering losses ranging from 30 paise to 60 paise per unit by supplying power to farm sector at subsidised rates. Seven SEBs are suffering loss exceeding 50 paise per unit for supplying to agricultural consumers and four SEBs are suffering a loss of about 40 paise per unit on the average. The biggest sufferers on this account are the four State Electricity Boards of Punjab, Haryana, Rajasthan and Uttar Pradesh in the Northern Region as the consumption of electricity by the farm sector served by these SEBs is well over 30 percent of their total consumption.

Why should the SEBs be made to suffer this unduly high financial loss on power supply to agriculture? The policy of providing heavily subsidised power to the farm sector which is totally unrelated to the cost of production is misplaced. The benefits of cheap power actually go to the affluent farmer who is in a position to run his agricultural macinery even on much costlier diesel oil when there is no electricity. He is very well in a position to pay for the full cost of the power he uses. Another programme which is draining the vitality of the Boards is the vast and unremunerative rural electrification programmes carried out lately by the States regardless of the technical and commercial considerations. Initially the intention of the State Governments was to partly cross-subsidise the agricultural sector by suitably adjusting the tariff for power supply to other sectors and partly by giving subsidies to the Boards to compensate for the losses suffered by them on account of power supply to the farm and rural sectors. Over the years, however, whereas the practice of supplying electricity at subsidised rates to the agricultural-cum-rural sector continues, the State Governments' promised subsidies to the SEBs have stopped pouring in as the financial position of most of the State Governments does not permit them to give these subsidies. This has resulted in multiplying the losses of the Boards through no fault of theirs.

In some States, even the Small Scale Industries are being supplied electricity at heavily subsidised rates. In 1985-86 the loss incurred by SEBs on this account has been estimated at Rs.11 crore.

Since the unremunerative tariff structure for supplying farm sector alone is at present responsible for causing about 80 percent of the total losses of the Boards, the question arises as to whether the SEBs are to be treated as commercial undertaings earning a small profit to finance their development activities after covering their expenses, or they should be treated by the State Governments as

instruments of social change and for promoting their policies of social welfare. In this context, it may be pertinent to mention that the Electricity (Supply) Act, 1948 as amended in June 1978 has introduced provision for making the SEBs commercially viable and earn a net return on their investments. If the SEBs are to get out of the present rut, it should be clearly recognised by the State Governments that the Boards are meant to be run as commercially viable undertakings and not as charitable institutions.

Over-Staffing

Power industry generates employment but is not by itself employment intensive. Too many workers with little work to do give rise to more operational and management problems. In the SEBs there is over-staffing particularly in the areas of Thermal Generation and Distribution. It has been assessed that the extent of over-staffing in the Power Industry is in the neighbourhood of 25-30 percent as compared to normative standards. It is interesting to note that while there is shortage of staff in the category of qualified technicians, operators and supervisory staff there is a large surplus staff in the category of unskilled and semi-skilled personnel. Average number of employees per million units supplied during 1985-86 by the SEB's is 7.3 (Planning Commission) as against an average of 5.5 employees/MU employed by the State Electricity Boards of Andhra Pradesh, Madhya Pradesh and Maharashtra. Adopting this as a desirable norm for all the SEBs possible reduction in revenue expenditure would be Rs.339 crore (Annexure-I).

Low Productivity of Power Plants

The Rajadhyaksha Committee on Power had assessed a plant load factor (PLF) of 58 percent to reflect good thermal performance. Thermal power development in the seventies and eighties mainly comprises units of 200/210 MW and 100/110/120 MW. While units of 200/210 MW have now stabilised to give an average PLF of 59.6 percent taken for the country as a whole (and about 74 percent taking the best

performance), the 110 MW units are still not out of the woods from the generic and specific defects. Their overall PLF is of the order of 44 percent. The maximum concentration of these units is in the Northern and Eastern Regions where the PLF is considerably depressed due to these units. Improvements are also needed in the 120 MW units as well. It would be realistic, therefore, to consider that for the present, if a PLF of about 55 percent is achieved against 49.2 percent as average for all SEBs during 1985-86 (CEA), this could be taken as a good performance. In our analysis, therefore, a target of 55 percent PLF has been considered desirable and capable of achievement. This would result in availability of additional 6552 MU which in turn would accrue additional revenue amounting to Rs.80 crore (Annexure-I).

Higher Fuel Consumption

Thermal Power Plants in the country at present consume about 0.72 kg of coal and about 16 ml of fuel oil per unit generated which is rather high. The higher consumption is mainly due to the coal supplied being of much inferior quality compared to the normative one. In addition, the coal supplies received by the power stations contain a lot of extraneous matter, viz., shale, overburden and stones. Further, the quantity received at the Power Stations is on an average about 15 percent short in weight. All this is reflected in a higher fuel consumption.

Fuel oil consumption is also high on account of the bad quality of coal. The higher consumption particularly occurs during the rainy season when the moisture content of coal is high and often it is muddy and mixed with clay. Comparatively higher consumption is also due to frequent start-ups of units because of unduly high occurrances of tube failures and other forced outages. There is, however, some scope to reduce the fuel consumption to the level of 0.65 kg Coal/Kwh of average quality of coal for Thermal Stations and 10 ml fuel oil/Kwh which can be rasonably achieved. This would result in savings in revenue expenditure amounting to Rs.174 crores for coal and Rs.143 for fuel oil on 1985-86 consumption and price index (Annexure-I).

Low Operation and Maintenance Expenditure

The actual expenditure on O&M (which mainly comprises O&M stores, spares and services) presently being incurred by the SEBs is rather low as compared to normative standards. It is also seen that in the Thermal Power Plants the planned maintenance outage is actually about 8.5 percent only as against a desired value of about 11.5 percent for such plants under existing working conditions with particular reference to the quality of coal being used. These are indicative of the fact that the Thermal Plants in the country are being deprived of proper maintenance which is contributing to their poor performance. On the Transmission and Distribution side also due to poor provisions made on the O&M side, the reliability of the system remains below desirable standards. The present expenditure of 5.08 p/Kwh on O&M is, therfore, quite inadequate and has to be stepped up by atleast 40 percent, i.e., about 2 p/Kwh. Additional expenditure on this account will amount to Rs.226 crore (Annexure-I).

Higher Auxiliary Consumption

Auxiliary Power Consumption in the Thermal Stations in 1985-86 was of the order of 11.4 percent. The higher auxiliary consumption is mainly in the coal and ash handling plants and milling system due to the problems of sub-standard coal supplies. The coal handling plants have to work almost for three shifts although these are planned for two shift operation. Higher axiliary consumption is also reflected by its low plant load factor. However, the reduction of auxiliary consumption from 11.4 to 10 percent is capable of achievement and this would result in availability of 864 MU additionally which in turn would earn an additional revenue of Rs.48 crore (Annexure-I).

High Transmission & Distribution Losses

The actual T&D losses in the country in 1985-86 have been of the order of 21 percent as against a figure of 15 to 16 percent that has been possible to be achieved in some of the developed countries. It would be worth making a realistic assessment and examining whether in our country it would be feasible to reduce the losses to a level of 15.5 percent from the present figure of 21 percent in the foreseable future.

All India figures of T&D losses in the Power Utilities during the last five years have been as follows:

1980-81	20.56%
1981-82	20.71%
1982-83	21.14%
1983-84	20.86%
1984-85	21.00%

The main reasons for the high T&D losses have been identified as long sub-transmission and distribution lines in many areas, low power factor loads comprising irrigation tubewell motors, multiplicity of stages of transformation, inadequate distribution system in urban areas, lack of proper administrative measures to prevent theft of electricity especially in the industrial sector and improper load management. While all possible efforts are being made by the SEBs to tackle the above problems for bringing down the losses, during the last five years, all that has been possible is to hold down the losses at 21 percent level. This itself might be considered to be an achievement considering the grossly inadequate funds made available to the Boards for 'Distribution and System Improvement Works' on the one hand, and the emphasis placed by the State Governments on the accelerated pace of rural electrification and tubewell energisation on the other. Taking all these factors into consideration, it is felt that if all the measures being contemplated by the State Governments and SEBs are enforced vigorously and adequate funds are made available to them for 'Distribution and System Improvement Works' hopefully by end of 1989-90 it might be possible to bring down the T&D losses to 18 percent level. In this connection it has to be emphasised that if we are really serious about reduction of T&D losses, the investment pattern on T&D Sector has to undergo a drastic review. Whereas it has been recommended by experts in this field that for evolving a cost-effective system it would be necessary that the investments on generation should be matched by an equal investment on Transmission

and distribution, in actual practice at present the investments in Transmission & Distribution are only 1/3rd of the total investments. This distortion has to be corrected if we are really interested in reducing the T&D losses.

Additional revenue that could have accrued by reducing the T&D losses from 21 to 16 percent amounts to Rs.237 crore on account of availability of 4291 MU additionally (Annexure-1).

The above analysis shows that if the desirable normative levels in employment, PLF, T&D and auxiliary losses as well as in fuel consumption could be achieved there would be additional 11707 MU available and would result in saving to the tune of Rs.795 crore on 1985-86 levels, as summarised in the Table-I below:

TABLE-I

		Units gained (MU)	Saving (Rs. crore)
1.	Establishment	-	339
2.	Transmission & Distribution losses	4291	237
3.	PLF	6552	80
4.	Aux. Consumption	864	46
5.	Coal Consumption	-	174
6.	Oil Consumption	-	143
7.	O&M	-	(-)226
	Total	11707	795

Thus the loss of Rs.1438 crore incurred by the SEBs in 1985-86 could have been reduced to Rs.643 crores (i.e. Rs.1438 crore - Rs.795 crore) with the desired normative levels of staffing, higher PLF, lower Auxiliary and T&D losses, etc., as discussed above.

The total losses of the SEB's due to unremunerative tariff structure and the present sub-optimal standard of technical performance are as shown in Table-II.

TABLE-11

		Losses (Rs. in Crore)	Percentage
1.	Low agriculture tariff	1134	50.78
2.	Low tariff for Small Industry	11	0.49
3.	Low tariff in other categories	293	13.13
4.	Over staffing	339	15.18
5.	High T&D losses	237	10.62
6.	Low PLF	80	3.56
7.	High auxiliary consumption	48	2.15
8.	High Coal consumption	174	7.79
9.	High fuel Oil consumption	143	6.40
10.	Low O&M provisions	(-) 226	(-) 10.12
		2233	100.00

The above table is very revealing. It is seen that about 80 percent of the losses are attributable to non-technical reasons, viz., about 65 percent to adoption of unremunerative tariffs and 15 percent due to overstaffing in the Boards. The balance, 20 percent are attributable to low PLF, high fuel consumption, high T&D and auxiliary losses after, however off-setting 10 percent due to low provisions made for operation and maintenance.

No doubt there is ample scope for improvement in the technical performance of the Boards, but the important fact that emerges from this study is that in order to revitalise the SEBs, greater emphasis has to be put on the major factors that are draining the vitality of the Boards. In other words the SEBs should be allowed to function as viable commercial enterprises by permitting them to adopt remunerative tariff structure (especially for the agriculture sector). At present the relative emphasis being put by concerned authorities for taking corrective action regarding the different causative factors leading to poor performance is somewhat distorted.

Too much emphasis is being laid on improving PLF of Thermal Stations, reduction of T&D losses, etc., whereas the non-technical factors like imposition of unremunerative rates for power supply to certan categories of consumers and forcing the SEBs to resort to over employment which contribute to a major portion of the total losses suffered by the Boards, are being ignored.

The Planning Commission have analysed the structure of the operating costs of the SEBs for the year 1985-86 and have worked out the breakdown of costs (paise/Kwh of energy sold) for each of the relevant parameters, viz., fuel, O&M, Establishment, Interest and Depreciation, etc., and have arrived at an average figure of 69.53 paise/unit as the total cost of a saleable unit of energy. It will be interesting to work out the hypothetical adjusted cost per unit by making necessary adjustments to the individual components as estimated on the basis of informal norms of performance.

Table III gives the cost in paise per unit of energy sold, in respect of each of the components constituting the operating cost, the scope for adjustment on each of these on the basis of the previous discussions and, finally the adjusted cost per unit of saleable energy (Annexure-II).

TABLE-III

Structure of Operating Cost & Possible Cost Adjustments

(p/Kwh of energy sold)

Item	As per Planning Commission Analysis	Scope for Adjustment due to		Adjusted cost
		Increased Generation	Other Factors	
1. Fuel	19.86+(3.79)*	-	(-) 2.47	21.18
2. Interest	15.09+(2.88)*	(-)1.86	-	16.11
3/ Depreciation	5.35+(1.02)*	(-)0.66	-	5.71
4. Establishment	12.13+(2.32)*	(-)1.50	(-) 2.99	9.96
5. O&M	5.08+(0.97)*	(-)0.63	(+) 2.62	8.04
6. Miscellaneous	0.87+(0.17)*	(-)0.11	-	0.93
	58.38+(11.15)	(-)4.76	(-) 2.84	61.93
Total	=69.53			

* The figures in the brackets are the break up of the purchase element given in Planning Commission's analysis into various components proportionately.

It will be seen from Table-III that by taking necessary steps to reduce the fuel consumption and over-staffing, making desirable higher provision towards operation and maintenance expenses for improving the standards of O&M and taking into account availability of additional units due to reduced T&D losses, higher PLF and lower aux. consumption it would be possible to bring down the operating costs per unit from 69.53 paise to the level of 61.93 paise per unit.

Additional Provisions Necessary

In addition to the normal operating expenditure chargeable to revenue which includes interest on working capital, the SEBs have to generate internal resources to meet the yearly liability on account of :

(i) Payment of interest on loans taken from financial institutions and on market borrowings;

(ii) Repayment of loans taken from financial institutions and market.

They have also to meet part of capital expenditure on new works during the year. For this purpose SEBs have committed to the Financial Institutions raising of atleast 20% of the capital expenditure during the year from internal resources. Provision has therefore, to be made towards this in the revenue receipts.

Providing 15 percent interest on working capital (taking the working capital as 1/6th of revenue expenditure excluding interest and depreciation charges) and making provision of 20 percent of operating expenditure towards generation of internal resources of the SEB's, the average sale price works out to about 75 paise/Kwh as shown below:

(i)	Interest on working capital @ 15% on 1/6th of Revenue Expenditure of Rs.5548 crore (Excluding interest & depreciation - Annexure-III)	Rs. 138 crore

(ii)	Provision for generation of Internal resources for meeting interest charges on works in progress, repayment of loans and New capital works @ 20% of operating expenditure of Rs.7858 crore (Annexure-III)	Rs.1572 crore
	Total	Rs.1710 crore

∴ Net additional Provision required = Rs.(1710+643) crore
= Rs.2353 crore

Total units available for sale = 124733 MU

Increase in tariff = 18.86 p/Kwh

∴ Revised tariff = 55.2 + 18.86
= 74.06 p/Kwh

It may be mentioned in this connection that NCPU has carried out another exercise for working out a rationalised tariff structure based on realistic input costs and normative standards of efficient operation and the average sale price per unit, according to this exercise also, works out to 75 p/unit.

Based on this average sale price of 75 paise/unit a rationalised tariff pattern applicable to different categories of consumers could be worked out in such a manner that the loss incurred by SEBs by selling power to the agriculture or any other sector at concessional rates is made up by cross subsidisation among the various categories of consumers. In order to enable the SEBs to come out of their present financial difficulties it would be necessary to revise the agricultural tariff to a somewhat remunerative level from the present level which is unrealistically low and has no relation to the costs of production. It has been estimated that if the agricultural tariff is revised marginally so that it has some semblance of relation with the cost of inputs, the increase in price of wheat will be only

marginal to the extent of about 7 paise per kg. The Agricultural Prices Commission should take into account all the input costs including Electricity while fixing prices of Agricultural products so that SEBs do not suffer such high revenue losses necessitating subsidy on this account which the State Governments are unable to afford Similarly the SEBs are incurring losses because they are being made to supply power to the small industries at unremunerative rates, and thi distortion also has to be corrected. For these Industries, powe costs form only a small percentage of the total cost of the fina product and there does not seem to be any justification for them to b supplied power at subsidised rates. If any particular Industry is t be encouraged in some backward areas, the incentive could be in th form of Electricity Duty Relief to be given by the State Governmen rather than putting the burden on the already ailing SEBs.

Based on the above consideration the following tariff patter is suggested:

(i)	Average tariff	75 paise/uni
(ii)	Agricultural tariff @ 67% of average tariff	50 paise/un
(iii)	Domestic Tariff:	
	(a) Consumption below 30 Units/month @ 75% of Average tariff	55 paise/un
	(b) Consumption between 30 and 80 units/ month @ Average rate	65 paise/un
	(c) Consumption above 80 unit/month @ 115% of Average rate	75 paise/un
(iv)	Commercial Tariff:	
	(a) Consumption upto 80 unit/month @ 120% of standard rate	90 paise/un
	(b) Consumption higher than 80 unit/month @ 133% of average rate	100 paise/un
(v)	Small Industry @ average rate	75 paise/ur
(vi)	Medium & Large Industry @ near to marginal cost	90 paise/ur
(vii)	Miscellaneous consumers	75 paise/ur

The above tariff does not include Electricity duty which is chargeable separately at varying rates from 3 p to 15 p/Kwh for different categories of consumers so as to yield an average of about 5 p/Kwh sold.

The adoption of the above pattern of rationalised tariff structure based on cost of inputs would enable the SEBs to come out of the red and would give them a chance to function as viable commercial enterprises. Improvement in the financial health of the Boards would also make them less dependent on Government loans and subsidies, eventually leading them to regain their autonomous character. This would trigger off a healthy chain reaction in improving the technical performance of the SEBs as due to their improved financial condition they would be able to invest their funds in more purposeful manner like improvement of Transmission and Distribution faclities which would result in lower T&D losses, and this in turn would further improve their revenue earning capability. Performance of the Thermal Power Stations would also improve as the increased earnings would enable them to procure adequate spare parts resulting in better maintenance of machinery and equipment leading to improvement in plant load factors. Taking the SEBs out of the red will be a morale booster all around and would help in providing much needed relief to the harassed consumers whether in the domestic or agricultural sector or in the Industrial sector whose very existence is threatened due to chronic power shortages.

ANNEXURE-I

1. **Excess Expenditure due to Over-staffing**

Total number of employees (Planning Commission) = 826600

Total number of Units Sold = 113016 MU

$$\text{Number of employees/MU} = \frac{826600}{113016} = 7.3$$

Desirable number of employees/MU = 5.5

Overstaffing = 7.3-5.5 = 1.8 men/MU

Establishment cost (Planning Commission) = 12.17p/unit

Additional Expenditure due to overstaffing

$$\frac{113016 \times 12.17 \times 1.8}{7.3} = \text{Rs.}339.14 \text{ crore}$$

2. **Revenue Loss due to Higher T&D Losses**

Total units sold = 113016 MU

Actual T&D loss = 21%

i.e. Actual availability = 79%

Desirable availability = 82%

(i.e. 18% losses)

$$\text{Units gained on 82\% availaility} = \frac{(113016 \times 82)}{79} - 113016$$

= 4291 MU

$$\text{Revenue loss} = 4291 \times \frac{55.2}{100} \times 10^6 = \text{Rs.}236.86 \text{ crore}$$

3. **Revenue Loss due to Low PLF**

Units generated by Thermal Stations in 1985-86 by Boards (Planning Commission) = 75310 MU

Actual PLF [All Boards (CEA)] = 49.2

Desirable PLF = 55

Additional units generated at PLF 55% = $\frac{75310 \times 55 - 75310}{49.2}$

= 84188-75310

= 8878 MU

Deduct 10% aux, losses = 8878-888 = 7990MU

Deduct 18% T&D losses = 7990-1438

Net additional units available = 6552 MU

Gross revenue lost on 6552 MU = $\frac{6552 \times 55.2 \times 10^6}{100}$

= Rs.361.67 crore

Deduct cost of fuel for units lost (@ 27.63 p/unit (Planning Commission) = $\frac{8878 \times 27.05 \times 10^6}{100}$

= Rs.240.15 crore

Deduct O&M expenditure for units lost @ 5.08 p/unit (Planning Commission) = $\frac{8878 \times 5.08 \times 10^6}{100}$

= Rs.41.10 crore

Net Revenue loss = 361.67-(240.15 + 41.10) = Rs.80.42 crore

4. Revenue Loss due to High Aux Consumption

Aux. Consumption-Average of Boards (Planning Commission) = 11.4%

Desirable Aux. Consumption = 10% (Assumed)

Units gained by lower Aux. Consumption = $\frac{75310 \times 1.4}{100}$

= 1054 MU

1054x18

Deduct T&D losses @ 18% = --- = 190
100

Net units gained = 1054-190 = 864MU

Net Revenue loss $\frac{864 \times 55.2 \times 10^6}{100}$ = Rs.47.69 crore

5. **Excess Expenditure due to High Coal Consumption**

Total Coal Consumption = 5,13,87000 MT
Actual Consumption/Unit = 0.72 kg/unit
Desirable Coal Consmption/Unit = 0.65 kg/unit
Excess Consumption/Unit = 0.07 kg/unit

∴ Revenue loss @ Rs.331/ton = $75310 \times 0.07 \times 0.331 \times 10^6$
= Rs.174.49 crore

6. **Excess Expenditure due to High Oil Consumption**

Total oil consmption = 1129900 KL
Actual Oil consumption/unit = 15.9 ml/kwh
Desirable Oil consumption = 10 ml/kwh
Excess oil consumption/unit = 15.9-10 = 5.9ml

∴ Revenue loss @ Rs.3210/KL = $\frac{75310 \times 5.9 \times 3.5 \times 10^6}{1000}$
= Rs.142.63 crore

7. **Additional O&M Cost**

O&M Cost = 5.08 p/Kwh (Planning Commission)

The present provision for O&M is not adequate and has to be stepped up by at least 40%, i.e., about 2 p/kwh.

Additional expenditure on this account will amount to (113016x2p), i.e., Rs.226 crore.

ANNEXURE-II

Adjustments

Coal

Fuel cost = 19.86p/unit of energy sold (Planning Commission)

Average Rate = Rs.331/ton (Average Planning Commission)

Reduction from 1985-86 figure of 0.72 to the desired level 0.65 = 0.07 kg/kwh

Cost reduction = 33.1x0.07 = 2.317 p

Oil

Average rate for oil = Rs.3210/KL

Reduction from 15.9 ml/kwh to 10 ml/kwh, i.e. = 5.9 ml/kwh

∴ Total cost reduction = 0.3210x5.9 = 1.894 p/kwh

Total cost reduction in fuel due to adoption of norms as above = 2.317+1.894 = 4.211 p/kwh

As the Thermal generation is 58.7%

∴ Net adjustment = 4.21x58.71 = 2.47 p/kwh

Establishment

Establishment = 12.13 p/kwh when 7.3 employee exist (Planning Commission) per MU

With 5.5 employees as desirable reduction in cost of establishment $= \frac{12.13 \times 1.8}{7.3} = 2.99$ p/kwh

O&M

O&M cost = 5.08 p/kwh (Planning Commission)

The provision for Maintenance is not adequate. The O&M expenditure will increase by about 40%, i.e., 2p/kwh if adequate provision for maintenance is made.

ANNEXURE-III

Calculations for Operating Expenditure and Revenue Expenditure

No. of units sold	= 113016 MU
Operating cost	= 69.53 p/kwh
Operating Expenditure	= 69.53x113016 MU
	= Rs.7858 crore
Interest to Institutional investors	
& State Government	= 6.37+8.72=15.09 p/kwh
Depreciation	= 5.35 p
∴ Interest & depreciation	= 15.09+5.35
	= 20.44 p/kwh
∴ Revenue Expenditure	= 7858-(20.44x113016)
	= 7858-2310
	= Rs.5548 crore

NATIONAL COUNCIL OF POWER UTILITIES

ELECTRICITY PRICING

1. Introduction

1.1 Electricity is one of the key inputs that contributes to the growth of the national economy. Industry cannot run without electric power, a present day farmer is as much dependent on electricity as the industry, and the common man, whether the relatively prosperous city dweller or the humble farmer, has found in electrical power, a most convenient form of energy which has revolutionised his way of life. Thus providing cheap and dependable power supply to the consumers has been one of the prime concerns of the Government.

1.2 In India, primarily the State Electricity Boards have been entrusted with the task of generation, transmission and distribution of power. Although it is intended that the SEBs should function as viable commercial undertakings earning a small profit after meeting their expenses, in actual practice due to various reasons, they have not been able to function as such. As a result they have been incurring heavy financial losses. Planning Commission has estimaed that in the fiscal year 1985-86 alone the SEBs have incurred a loss to the tune of Rs. 1438 crores.

1.3 NCPU has analysed in depth the various reasons that have caused the SEBs to suffer such heavy losses. For this analysis NCPU has made use of the basic data furnished in the Annual Report on the working of State Electricity Boards and Electricity Departments - April, 1986, of the Power & Energy Division of the Planning Commission. This analysis has revealed that one single factor that has been responsible for about 80% of the financial losses suffered by the SEBs in 1985-86 has been the unremunerative rates for sale of electricity to the consumers especially the farm sector. Contrary to popular belief, therefore, it is not the technical and managerial

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incompetence of the SEBs alone that has been primarily responsible for their financial difficulties. The NCPU analysis (even the Planning Commission analysis) shows that the SEBs are being made to sell electricity to certain category of consumers at prices much below their cost of production. Under such conditions no amount of improvement in PLF of thermal stations and reduction of transmission and distribution losses (which contribute comparatively lesser percentage towards the total financial losses) will help the SEBs to come out of the red. It is in this context that the NCPU undertook an exercise to evolve a rational pattern of tariff structure based on input costs and normative standards of efficient operation and management, and at the same time keeping in mind the interest of the agricultural consumers, small domestic consumers as well as consumers in the small industries sector.

2. <u>Tariff Structure Based on Input Costs & Normative Standards</u>

2.1 While formulating a rational tariff structure, it has to be kept in mind that certain sections of the consumers such as agricultural consumers, domestic consumers in rural areas and those consuming less than certain specified amount of power have to be charged at lower rates. On the other hand, certain other categories of consumers such as commercial and some medium and heavy industries where the cost of power forms only a small percentage of their total costs are in a position to bear a higher tariff rate without affecting the prices of their final product to any appreciable extent. Thus there is scope for cross subsidisation among the different consumer categories. The ultimate objective is that the losses suffered by the SEBs in power supply to agriculture and small industries at unremuneratively low rates are made up by increasing the tariffs suitably for those categories of consumers who are in a position to bear such increases. The revised tariff for these consumers should be such as to enable the Power Utilites to earn a small profit after providing for depereciation and interest payments, statutory provision for which has been made in the Electricity Supply Act for this purpose. Taking the above factors into consideration, an attempt has been made to formulate a rationalised tariff structure for

Electricity Supply (vide Appendix). The various assumptions made are based on realistic input costs and normative standards of efficient operation as laid down in Rajadhyaksha Committee Report as also relevant recommendations made by bodies like Central Electricity Authority, Planning Commission, etc.

2.2 Assumptions Regarding Norms

2.2.1 Plant Load Factor & Auxiliary Consumption

For efficient operation of power plants Rajadhyaksha Committee on Power has recommended for Thermal Stations a Plant Load Factor of 58% and auxiliary consumption of 10%. As against this, on an All India basis, the actual PLF realised so far by the SEBs has been 47.2% in 1983-84, 45.1% in 1984-85 and 49.2% in 1985-86. In our calculations therefore a realistic figure of 55% PLF has been assumed which may not be considered unreasonably low considering the various constraints the Power Utilities have to face especially in regard to the quality of coal and some of the equipment available to them to run the power stations. Auxiliary consumption has been assumed at 10% as recommended by Rajadhyaksha Committee.

2.2.2 Transmission and Distribution Losses

As is well known, due to various reasons, T&D losses in our power systems are high compared to power systems in relatively developed countries. The T&D losses during the last five years have been varying in the range of 20.56% to 21.14%. In spite of the various technical and administrative measures taken by the SEBs during this period, it has been possible to hold the T&D losses to the level of 21% only. This itself may be considered to be an achievement considering the inadequate investment of funds in the "Distribution & System Improvement Works" on the one hand and the greater emphasis being put by the State Governments on their programmes of rural electrification and energisation of tubewells, etc., which generally involves extending of Distribution and LT lines without strengthening the back up transmission and distribution systems. Taking all these factors into consideration, on a realistic assessment it is felt that by 1989-90 it might hopefully be possible to bring down the losses to the level

of 18% from the past five years' level of 21%. The tariff calculations are therefore based on a figure of 18% for T&D losses (as against the prevailing figure of 21%) so that the consumer gets the advantage of the lower losses expected to be achieved after five years or even later.

As regards the assumptions in regard to the break-up of the losses occuring in the various system elements (EHV transmission system, EHV transformation to intermediate voltage level, subtransmission system and step down to distribution voltage level and finally distribution lines and services), these are shown in Annexure I. The relative distribution of the total loss of 18% among the various system elements is based on the limited data available for Indian systems.

A schematic diagram showing the distribution of the net generated units (KWH) at the various voltage levels/system elements is shown in Annexure II. The figures for sales of electricity at the EHT, HT and LT busses are based on statistics primarily relevant for the SEBs.

2.2.3 Other Assumptions

(i) Capital Costs

The historical costs per KW of the Generating Plants, Transmission, sub-transmission and distribution systems are, by and large, based on the investments made in the various plan periods on the respective works covering the period upto Sixth Plan (vide Annexure III). The present costs are based on corresponding investments during Seventh Plan period.

(ii) Interest & Depreciation

Interest has been calculated at the average rate of 10.5% per annum on sum-at-charge on the assumption that net worth of capital assets is 80% of the original cost.

Depreciation on the various items has been assumed as per the relevant provisions in the Indian Electricity Supply Act.

(iii) Working Capital

Provision of working capital has been made @ 1/6th of Revenue expenditure.

(iv) Provision for Generation of Internal Resources

In the calculations provision has been made at the rate of 20% of the yearly revenue expenditure for meeting interest charges on works in progress, repayment of loans and part expenditure on new capital works.

3. <u>Considerations in Structuring Model Tariff Based on Input Costs</u>

3.1 As already stated, on all-India basis the SEBs have incurred a loss of aout Rs. 1438 crores in 1985-86. Out of this, about Rs. 1134 crores, account for losses towards supply to the Agricultural Sector alone. In spite of this, the SEBs are expected not only to meet their revenue expenditure in full but also to contribute about 15 to 30% for capital works expenditure from their internal resources. Seventh Plan is based on the profits of the public sector undertakings and if the Plans are to go through, the Boards cannot afford to incur such heavy losses. Rationalised tariffs particularly for agriculture are therefore necessary. It has been estimated that if a somewhat remunerative agricultural tariff is taken into consideration, the increase in price of wheat will not be more than about 7 paise per kg (vide Annexure IV). This increase in wheat price may be considered to be negligible considering that slight upward revision of agricultural tariff will help the SEBs in improving their financial condition to a great extent. It is, therefore, felt that there is ample scope for an upward revision of agricultural tariff without affecting the national economy. The State Governments could help the agricultural sector by giving them an indirect subsidy by not charging electricity duty on supply of electricity to agricultural sector. A similar subsidy could also be given to small domestic consumers who consume less than a certain amount - say 30 units per month.

3.2 Financial losses are also being incurred by the SEBs for supplies to Small Industries at unremuneratively low rates. It has been estimaed that losses on this account in 1985-86 amounted to about Rs. 11 crores. As already stated, since power costs form only a small percentage of total costs of the final product in the case of small industries, the power utilities should not be made to incur loss on this account and the burden should be borne by small industries

themselves. If any particular industry is to be encouraged in some backward areas, the incentive could be in the form of Electricity duty relief to be given by the State Government rather than tax the Power Utilities by making them sell power at unremuneratively low prices.

3.3 The above suggestions if adopted, will go a long way to help the Power Utilities in reducing their financial losses, enabling them to improve their revenues. This will help them to avoid transfer of capital resources to defray losses on revenue account as is being done now by a number of SEBs. With the improvement in their financial affairs, it will be possible for the SEBs to invest more funds towards improvement of Transmission and Distribution facilities resulting in lower T&D losses. This in turn will further improve the revenue earning capability of the Boards. As the increased earnings would enable the SEBs to procure adequate quanity of quality spare parts, the standard of maintenance of the Machinery & Equipment would also improve thus leading to improvement in the Plant Load Factor of thermal stations. This wil enable the much maligned SEBs to come out of the present morass and put them on a sound footing.

4. Results of Calculation of Electricity Tariff Based on Input Costs & Normative Standards (vide Appendix)

Calculations for fixing electricity tariff based on the methodology of normative standards mentioned in the preceeding paragraphs are given in the Appendix. The following is a summmary of the results of these calculations.

Table I

Break-up of Itemwise Cost per Unit

(Paise per Kwh)

Sl.	Item	Generation	Transmission	Sub Transmission	Distribution	Total
1.	Fuel	19.14	-	-	-	19.14
2.	Interest	8.60	3.67	1.29	3.69	17.25
3.	Depreciation	3.00	1.31	0.46	1.32	6.09

4. O&M	3.18	1.67	0.98	2.88	8.77
5. Establishment	1.40	0.33	0.66	6.70	9.09
6. Provision for Internal Resources Generation	7.06	1.40	0.68	2.92	12.06
7. Interest on Working Capital	0.88	0.17	0.08	0.37	1.50
Total	43.26	8.55	4.15	17.88	73.84

5. Average Sale Price Per Unit (KWh).

(i) Sale price of units sold at various levels/system elements.

E.H.T. Bus (132 kV/66 kV)

= Av. Cost per unit at Generator Bus + Trans. Cost

= 43.26 + 8.55 = 51.81

Say 52 P

(ii) Sale price of units sold at H.T. Bus (33 kV/11 kV)

= 52 + 4.2 = 56.2

= Say 56 P

(iii) Sale price of units sold at LT Bus

= 56 + 18 = 74 P

(iv) Out of the 82 units available (after allowing for 18% T&D losses), assuming that 20 units are sold at EHT, 18 units at HT and 44 units at LT (on basis of available statistics for SEBs), average sale price per unit works out to

$$\frac{20\times 52 + 18 \times 56 + 44 \times 74}{82}$$

= 64.7 Say 65 P

(v) Making allowance of 15% to cover increased capital costs, Average sale price

= 65 x 1.15

= 74.7 paise per unit

Say 75 P.

* The tariff cost of 65 P per unit is based on plant costs upto the end of Sixth Plan. If the plant capacities commissioned during first two years of Seventh Plan are taken into account, these costs will be at least 15% higher.

6. Fixing Consumer Categorywise Tariff taking the Standard Tariff Determined as above (75 paise/unit)

6.1 Having fixed the standard tariff as determined above (75 paise/unit), we have to now fix the tariff for different categories of consumers in such a manner that agricultural consumers and small domestic consumers are supplied energy at comparatively lower rates, and the losses incurred by the Power Utilities on this account are compensated by applying slightly higher tariff to other categories of consumers like commercial, medium and large industries on the rationale already discussed in the paper.

6.2 It may be mentioned tha the tariff calculations are based on the premise that out of 100 units of net generation available, 18 units are lost in T&D losses, the balance 82 units are therefore available for sale. The consumer categorywise break-up of these 82 units has been assumed as given in the following Table which is based on the data available in "Public Electricity Supply - All India Statistics: 1983-84: General Review" of CEA".

Table II

Category	Percentage	No. of Units
1. Agriculture	22.0	18
2. Domestic	11.5	9.5
3. Commercial	4.7	4.0
4. Small Industry	11.2	9.0
5. Large & Medium Industry	46.2	38.0
6. Others	4.4	3.5
	100.0	82.0

6.3 Based on the above the following tariff pattern is suggested for different categories of consumers:

(i)	Standard Tariff	= 75 paise/unit
(ii)	Agricultural Tariff @ 67% of Standard Tariff	= 50 paise/unit
(iii)	Domestic Tariff:	
	(a) Consumption below 30 units/month @ about 75% of Standard Tariff	= 55 paise/unit
	(b) Consumption between 30 & 80 units/month at about 85% of Standard Tariff	= 65 paise/unit
	(c) Consumption above 80 units/month @ Standard Tariff	= 75 paise/unit
(iv)	Commercial Tariff:	
	(a) Consumption upto 80 units/month @ 120% of Standard Tariff	= 90 paise/unit
	(b) Consumption higher than 80 units/month @ 133% of Standard Tariff	= 100 paise/unit
(v)	Small Industry @ Standard rate	= 75 paise/unit
(vi)	Medium & Large Industry - at about Marginal cost (Annexure V)	= 90 paise/unit
(vii)	Other miscellaneous consumers @ Standard rate	= 75 paise/unit

The above tariff does not include Electricity duty which is chargeable separately at varying rate from 3 p to 15 p/KWh for different categories of consumers so as to yield an average of about 5 p/KWh sold.

7. Revenue Calculations Based on Suggested Tariff Pattern

Revenue from		Paise
(i)	Agricultural consumers 18 units x 50 p	= 900.0
(ii)	Domestic Consumers*	
	(a) 0.70 x 9.5 units x 55 p	= 365.8
	(b) 0.28 x 9.5 units x 65 p	= 172.9
	(c) 0.02 x 9.5units x 75 p	= 14.3

(iii) Commercial Consumers*

	(a) 0.60 x 4.0 units x 90 p	= 216.0
	(b) 0.40 x 4.0 units x 100 p	= 160.0
(iv)	Small Industries	
	9 units x 75 p	= 675.0
(v)	Medium & Large Industries	
	38 x 90 p	= 3420.0
(vi)	Others	
	3.5 units x 75 p	= 262.5
	Total Revenue	= 6186.5

$\therefore$ Revenue earned per unit of

$$\text{Electricity Sold} = \frac{6185.5}{82} = 75.4 \text{ paise per unit}$$

Thus the revenue earned with the proposed tariff pattern almost matches the normative tariff of 75 p per unit worked out earlier. The power utility would therefore not incur any loss by adopting this tariff structure proposed for different categories of consumers.

* The consumers in the various ranges have been assumed as 70, 28 & 2% in the domestic and 60 and 40% in the commercial category

APPENDIX

TARIFF CALCULATIONS BASED ON INPUT COSTS & NORMATIVE STANDARDS OF PERFORMANCE

1.0	**Thermal Generation Cost/Kw**	
1.1	Number of units availale at generating Station busbars/kw per year with 55% PLF & after allowing 10% Auxiliary Consumption	= 4336 Units
1.2	Capital Cost/kw	
	Average Cost/kw - Historical	= Rs. 4,200.00
	Present day	= Rs.10,000.00
1.3	Annual Cost	
	(i) Interest @ 10.5 % on sum-at-charge (80% of Rs. 4,200.00)	= Rs. 352.80
	(ii) Depreciation @ 3.4% on Rs. 4,200.00	= Rs. 142.80
	(iii) Operation & Maintenance @ 1.5 % on Rs. 10,000.00	= Rs. 150.00
	(iv) Establishment @ 0.75 % on Rs. 10,000.00	= Rs. 75.00
	(v) Total cost	= Rs. 720.60
1.4	Fuel Cost	
	(i) Coal : 0.65 kg/kwh @ Rs 0.33 per kg	= 21.45 p/unit
	(ii) Oil : 10 ml fuel oil @ Rs.3,200/kl	= 3.20 p/unit
	(iii) Thus, fuel cost per unit generaed	= 24.65 p/unit
	(iv) Thus fuel cost per kW	= 24.65 x 4818
		= Rs. 1187.60
	Fuel cost per unit at Busbar	= 27.4 p
1.5	Total operating cost per kW delivered at generator bus bar 1.3 (iv) + 1.4 (iv)	= Rs. 1,908.00
1.6	Provision for generation of internal resources @ 20% of operating cost	= Rs. 381.60
1.7	Interest @ 15% on Working Capital (assuming working capital as 1/6th of Revenue Expenditure	= Rs. 47.7
	Sub Total (1.5+1.6+1.7)	= Rs. 2,337.5

1.8	Average cost per unit of net generation (per kw of installed capacity)	53.9 p
2.0	<u>Hydro Generation Cost/kwh</u>	
2.1	No. of units available at generator bus-bars per kw with 40% PLF, & after allowing 1% Auxiliary losses	= 3469 units
2.2	Capital Cost	
	Average cost/kw - Historical	= Rs. 4,000.00
	Present day	= Rs.11,000.00
2.3	Annual Cost	
	(i) Int. @ 10.5% on sum-at-charge (80% of Rs. 4,000.00)	= Rs. 336.00
	(ii) Depreciation @ 2% on Rs. 4,000.00	= Rs. 80.00
	(iii) Operation & Maintenance @ 0.8% on Rs. 11,000.00	= Rs. 88.00
	(iv) Establisment @ 0.2% on Rs.11,000	= Rs. 22.00
	Total Cost	= Rs. 526.00
2.4	Fuel Cost	= Nil
2.5	Total operating cost per kw delivered at generatpr bus-bar	= Rs. 526.00
2.6	Provision for generation of internal resources @ 20% of operating costs)	= Rs. 105.20
2.7	Interest @ 15% on working Capital (assuming working capital as 1/6th of Revenue Expenditure	= Rs. 13.16
	Sub-total (2.5+2.6+2.7)	= Rs. 644.36
2.8	Average cost per unit generated per kw of installed capacity	= 18.57 p/unit

3. <u>Average Generation Cost in the System at Generator Bus-bar terminals (Assuming 65:35 Thermal Hydro Mix)</u>

(i) Average Generation cost/kw = 2337x.65+644x.35 = Rs. 1744

(ii) Average Generation Cost/unit

$$= \frac{1744 \times 100}{4336x.65+3469x.35}$$

= 43.26 p/unit

4. <u>Transmission Cost per kW</u>

4.1	(i) Average number of units (net) available at Generator bus	= 4335x.65+3469x.35
		= 4032 units
	(ii) Number of units available at EHT bus after allowing for 3.5% Transmission & Transformation	= 4032 - 141
	losses	= 3891
4.2	Capital Cost	
	Average Cost/Kw - Historical	= Rs. 1,700.00
	Present Day	= Rs. 5,180.00
4.3	Annual Cost	
	(i) Interest @ 10.5% on sum-at-charge (80% on Rs. 1,700)	= Rs. 142.80
	(ii) Depreciation @ 3% on Rs. 1,700.00	= Rs. 51.00
	(iii) Operation & Maintenance @ 1.25% on Rs. 5,180	= Rs. 64.75
	(iv) Establishment @ 0.25% on Rs. 5,180	= Rs. 12.95
4.4	Total Operating cost (i)+(ii)+(iii)+(iv)	= Rs. 271.50
4.5	Provision for generation of internal resources @ 20% of total operating costs	= Rs. 54.30
4.6	Interest @ 15% on working capital (assumed as 1/6th of Revenue Expenditure)	= Rs. 6.78
4.7	Total Transmission cost per unit of electricity transmitted	= 8.55

5.0 <u>Sub-transmission Cost per kwh</u>

5.1	Number of units available for sale at 33 kV & 11 kV	
	(i) Assuming 20% as EHT sales, EHT Sales 0.2 x 4032	= 807 units
	(ii) Less 8.5 % losses in EHT/HT Transformer, HT line and HT transformer	= .085 x 4032
		= 342 units
	(iii) Net units available for sale at HT bus	= 3891 - (807+342)
		= 2742 units

5.2	Capital cost	
	Average cost/kW - Historical	= Rs. 420.00
	Present Day	= Rs. 1,800.00
5.3	Annual costs	
	(i) Interest @ 10.5% on sum-at-charge (80% on Rs. 420)	= Rs. 35.30
	(ii) Depreciation @ 3% on Rs. 420	= Rs. 12.60
	(iii) Operation & Maintenance @ 1.5% on Rs. 1800.00	= Rs. 27.00
	(iv) Establishment @ 1.0% on Rs.1,800	= Rs. 18.00
5.4	Total operating cost (i)+(ii)+(iii)+(iv)	= Rs. 92.90
5.5	Provision for generation of internal resources @ 20% of total operating costs	= Rs. 18.58
5.6	Interest @ 15% on working capital (assumed as 1/6th of Revenue Expenditure)	= Rs. 2.32
5.7	Total sub-transmission cost per unit of Electricity handled	= 4.15 p/unit'

6. <u>Distribution</u> <u>Cost</u> <u>per</u> <u>kWh</u>

6.1	Number of units available for sale to L.T. Consmers :-	
	(i) Assuming 18% as HT sales	= 0.18 x 4032
		= 726 units
	(ii) Units lost in LT network @ 6.0 %	= .06 x 4032
		= 242 units
	(iii) Net units available for sale to LT Consumers	= 2742 - (726+242)
		= 1774 units
6.2	Capital Cost	
	Average cost/kw - Historical	= Rs. 780.00
	Present day	= Rs. 3,400.00
6.3	Annual Costs	
	(i) Interest @ 10.5% on sum-at-charge (80% on Rs. 780.00)	= Rs. 65.50
	(ii) Depreciation @ 3% on Rs. 780.00	= Rs. 23.40
	(iii) Operation & Maintenance @ 1.5% on Rs. 3400	= Rs. 51.00
	(iv) Establishment @ 3.5% on Rs. 3,400	= Rs. 119.00
	Total Cost	**= Rs. 258.90**

6.4	Total Operating Cost (i)+(ii)+(iii)+(iv)	= Rs.	258.90
6.5	Provision for generation of internal resources @ 20% of total operating costs	= Rs.	51.78
6.6	Interest @ 15% on Working capital (assumed as 1/6th of Revenue Expenditure)	= Rs.	6.47
6.7	Total sub-transmission cost per kw	= Rs.	317.15
6.9	Cost of sub-transmission (paise per unit of Electricity)	= 17.88 p/unit	

ANNEXURE-I

PATTERN OF UTILISATION OF ELECTRICITY IN 1983-84.

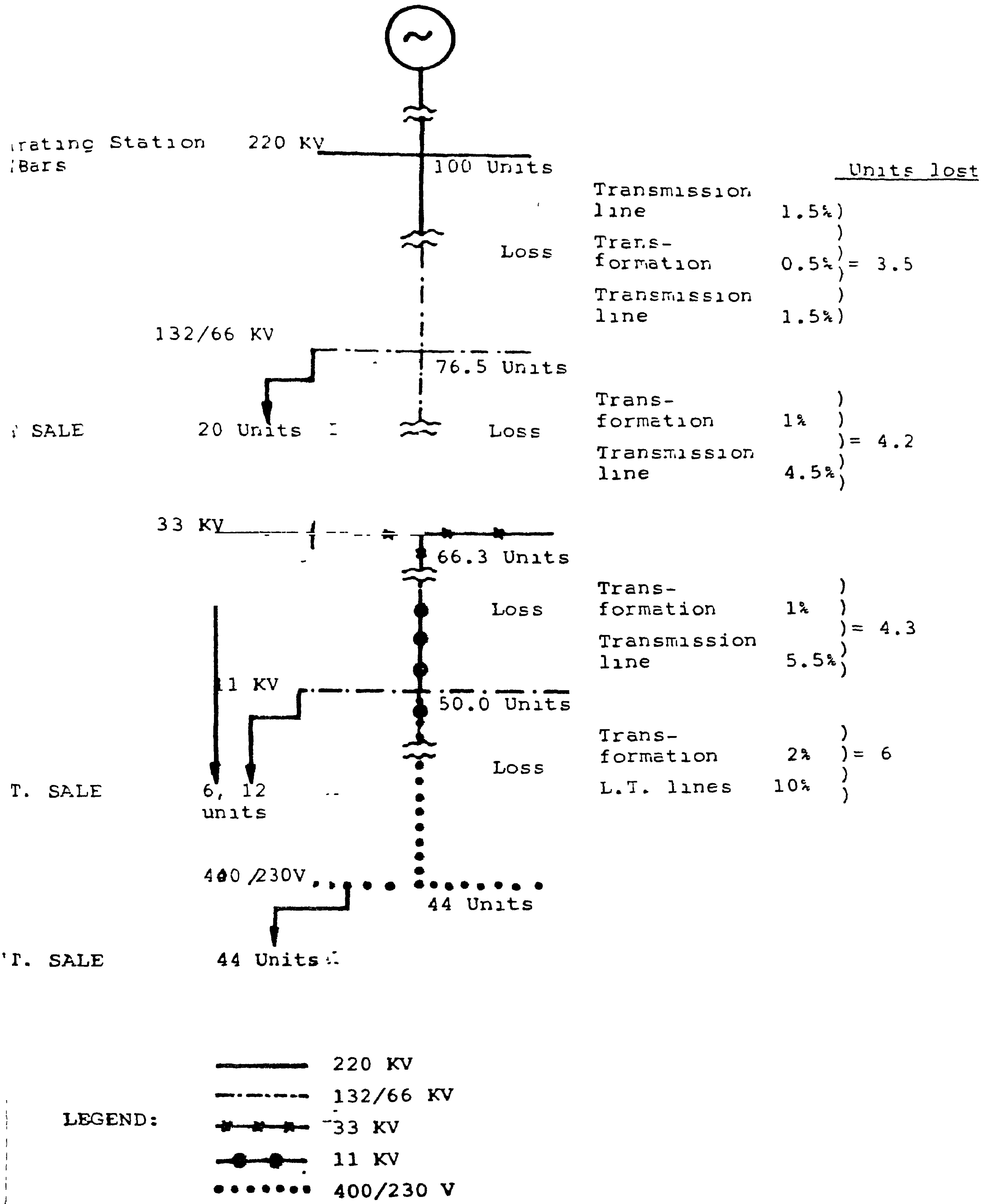
Category	Sales as % of total sales L.T.	Sales as % of total sales H.T.	Sales as % of units at generating station busbars with 18% T&D losses L.T.	Sales as % of units at generating station busbars with 18% T&D losses H.T.
Domestic	11.5	-	9.4	-
Commercial	4.7	-	4.0	-
Agricultural	22.0	-	18.0	-
Industrial - Small	11.2	-	9.0	-
Industrial - Medium & large	-	43.8)	-	38.0
Traction	-	2.4)		
Public lighting	0.9	-)	3.6	-
Others	3.5	-)		
Total	53.8	46.2	44	38
			82	

SALES & LOSSES AT VARIOUS VOLTAGE LEVELS OUT OF 100 UNITS AVAILABLE AT GENERATING BUSBARS.

Voltage level	% Losses in Trans-formation	% Losses in Lines	Units Trans-mitted	Units Lost	Units Sold
220/132/110/66 KV	0.5	3.0	100	3.5	20
33 KV	1.0	4.5	76.5	4.2	6
11 KV	1.0	5.5	66.3	4.3	12
400/230 V	2.0	10.0	50.0	6.0	44
Total				18	82

ANNEXURE-II

STATE ELECTRICITY BOARDS
SALES AT VARIOUS VOLTAGE LEVELS &
LOSSES IN SYSTEM ELEMENTS



ANNEXURE-III

Comparative Investment on Generation, Transmission Distribution & Rural Electrification

riod	Addition of Inst. cap. (MW)	Investment Rs. Crores Gen.	T&D	R.E.	Total	% (4)+(5)/(6) & (6)	Remarks
1	2	3	4	5	6	7	8
1-55)	110					.9	
	225					41.3	
	4570			153	1228	36.3	
al Plans	4188	676	271	237	1184	43.2	
	4157	1555	802	819	3176	51.7	
	7218	3152	1299	842	5293	40.1	
Plan)*	1800	1373	700	300	2473	48.0	
	14226	12072	5522	1671	19265	37.3	For VI Pla outlay inc proportion
upto end Plan	39509	20057	9212	4105	33374	40.0	
s. per VI Plan		5075	2331	1040	8446		
an	22245	10170	4216	1021	15407	33.4	

* In the absence of data of break up of figures for the year 1979-8 approximate estimated figures are assumed.

SOURCE: (1) COMMITTEE ON POWER

(2) CEA & PLANNING COMMISSION.